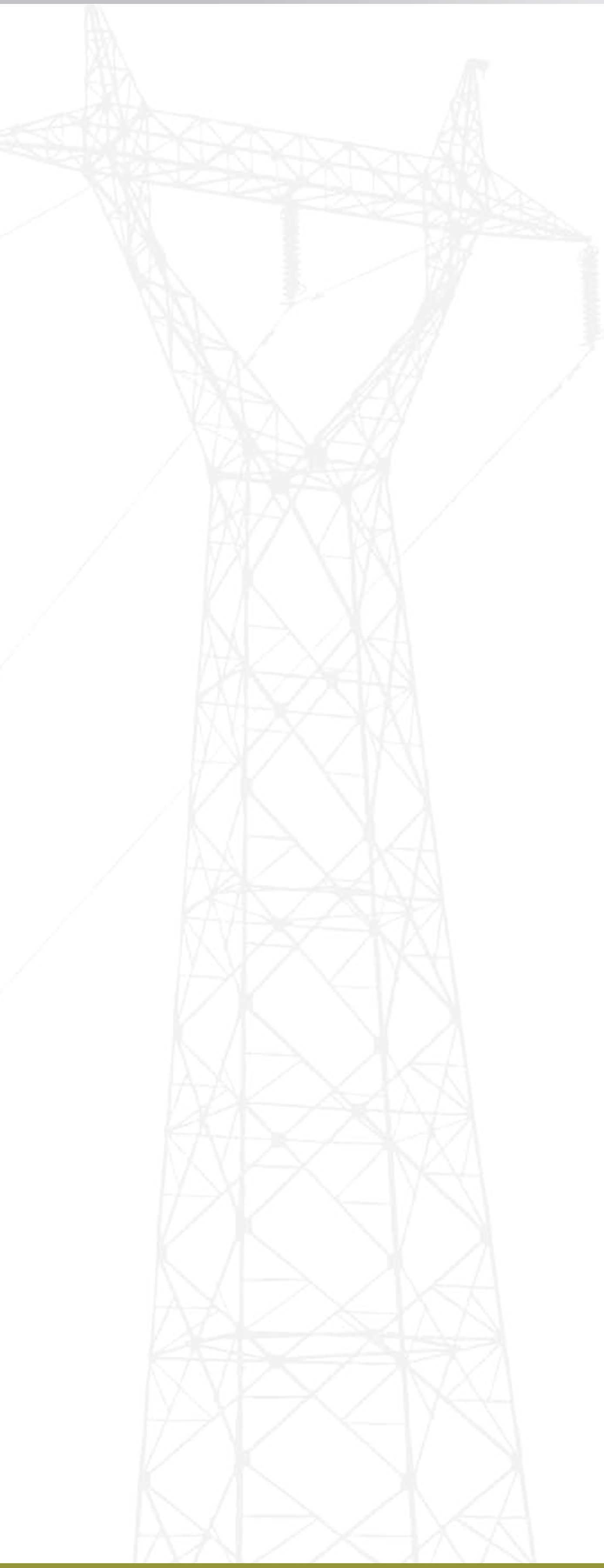
Smart Grid System Report

Annex A and B

U.S. Department of Energy

July 2009



Annex A

Metrics for the Smart Grid System Report

Table of Contents

Annex A

Metrics for the Smart Grid System Report

Introduction

This annex presents papers covering each of the 20 metrics identified in Section 2.1. These metric papers were prepared in advance of the main body of the report and collectively form its informational backbone. The list of metrics is derived from the material developed at the Smart Grid Implementation Workshop. The objective of the metric development process was to distill the best ideas into a small number of metrics with a reasonable chance of measurement and assessment.

The metrics examined in this annex are of two types: build metrics that describe attributes that are built in support of the smart grid, and value metrics that describe the value that may derive from achieving a smart grid. Build metrics generally lead the value that is eventually provided, while value metrics generally lag in reflecting the contributions that accrue from implementations. While build metrics tend to be quantifiable, value metrics can be influenced by many developments and therefore generally require more qualifying discussion. Both types are important in describing the status of smart grid implementation.

Each metric paper is divided into five sections as outlined below:

- Introduction and Background: A brief introduction to the concepts addressed by the metric, including an overview of relevant issues.
- Description of Metric and Measurable Elements: An identification and description of the metric being measured.
- Deployment Trends and Projections: The current status of the metric, analysis of trends and projections, identification of relevant stakeholders and their relationship to the smart grid, and assessment of regional influences on smart grid deployment.
- Challenges to Deployment: An overview of the technical, business, and financial challenges to smart grid deployment.
- Metric Recommendations: Recommendations to consider when preparing the next Smart Grid System Report to Congress.

The content in these metric papers are reproduced in sections of the main body of the report. References embedded in the report are designed to enable readers to trace content back to its original source here in Annex A.

Metric #1: The Fraction of Customers and Total Load Served by Real-Time Pricing, Critical Peak Pricing, and Time-of-Use Pricing

M.1.1.0 Introduction and Background

Historically, utilities have set prices on a flat-rate basis, unaffected by time of energy use, by the time-varying cost to the utility to supply the energy, or by time-varying power demand. The flat-rate system, while simple to understand and communicate to customers, does invariably lead to overconsumption of energy during peak periods when the cost to supply the power is at its highest point. Numerous studies have, in recent years, documented the pitfalls associated with flat-rate systems, and quantified the benefits associated with more dynamic pricing that varies based on the time of day or cost of power. One such study, which examined a number of pricing policies varying from time-of-use (TOU) pricing to critical-peak-period (CPP) pricing, found that these pricing policies could save the average customer \$3.94-\$8.02 monthly depending on the pricing system implemented.[1]

There are three principal pricing or tariff types covered in this section, as presented in Figure M.1.1.[2] Under a TOU tariff, prices are differentiated based solely on a peak- versus off-peak-period designation, with prices set higher during peak periods. TOU pricing requires smart grid technology—interval usage measurements found in advanced metering infrastructure (AMI)—and might be viewed as an intermediate step towards a more dynamic real-time pricing (RTP) tariff. Some TOU tariffs include a CPP tariff, where the

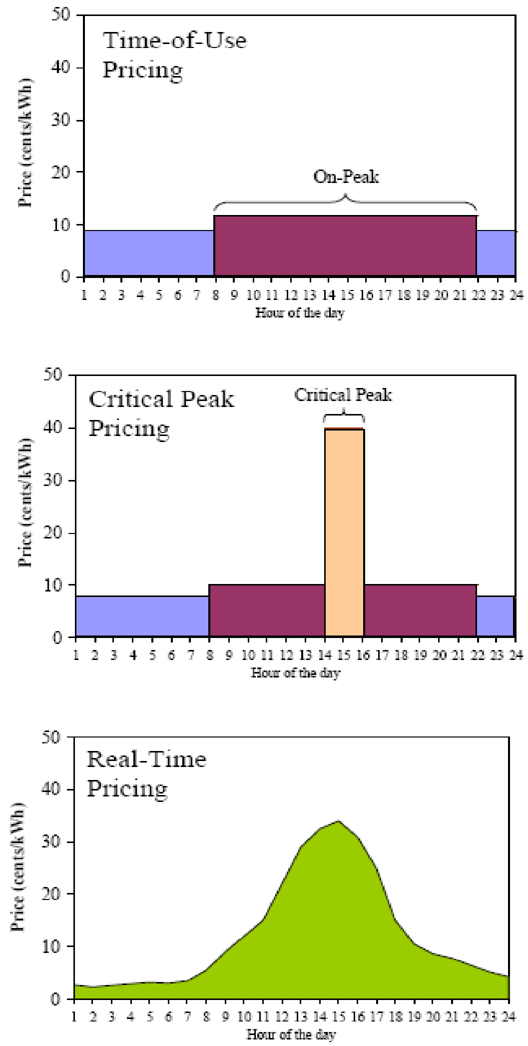


Figure M.1.1. Examples of Dynamic Pricing Tariff Structures

[1]Faruqui A and L Wood. 2008. *Quantifying the Benefits of Dynamic Pricing in the Mass Market.* Edison Electric Institute. Washington, D.C.
[2]Federal Energy Regulatory Commission (FERC). December, 2008. *Assessment of Demand Response and Advanced Metering.* FERC, Washington, D.C.

higher critical peak price is restricted to a small number of hours (e.g., 100 of 8,760) each year, with the peak price being set at a much higher level relative to normal conditions. Utilities may or may not provide advanced notice of impending CPP periods. Under RTP, at hourly or even shorter intervals, prices vary based on the day-of (real time) or day-ahead cost of power to the utility. Prices fluctuate throughout the day with the highest prices set during peak periods. RTP tariffs are the most dynamic of the three pricing structures and are therefore most dynamically responsive to peak-period consumption and energy costs.

M.1.2.0 Description of Metric and Measurable Elements

(Metric 1.a) the fraction of customers served by RTP, CPP, and TOU tariffs.

(Metric 1.b) the fraction of load served by RTP, CPP, and TOU tariffs.

M.1.3.0 Deployment Trends and Projections

RTP tariffs have historically been offered on either a voluntary or default (mandatory) basis, and only to industrial and large commercial accounts. To date, more than 70 utilities have offered voluntary RTP tariffs on either a temporary pilot or permanent basis. As of 2003, however, there were 43 tariffs offered on a voluntary basis, serving 2,700 customers collectively responsible for 11,000 MW of peak demand.[3] As of 2005, default RTP service was approved for implementation in five states – New Jersey, Maryland, Pennsylvania, New York, and Illinois. Within those states, default RTP service is in place for the largest commercial and industrial customers of ten investor-owned utilities (IOUs). Furthermore, default RTP service is proposed or planned for an additional 16 IOUs. The default enrollment in the ten participating utilities has reached nearly 1,000 MW.[4] When combined with the estimated load served under voluntary RTP tariffs, total RTP deployment reached approximately 12,000 MW, or 1.1% of total national net winter generating capacity.

The Federal Energy Regulatory Commission (FERC) conducted an extensive survey of demand-response and advanced-metering initiatives in 2008. The FERC survey was distributed to 3,407 organizations in all 50 states. In total, 100 utilities that responded to the survey reported offering some form of an RTP tariff to enrolled customers, as compared to 60 in 2006 (Table M.1.1). FERC also found through its 2008 survey that 315 utilities nationwide offered TOU rates, compared to 366 in 2006. In those participating utilities, approximately 1.3 million electricity consumers were signed up for TOU tariffs, representing approximately 1.1% of all U.S. customers (Table M.1.1). In 2008, customers were enrolled in CPP tariffs offered by 88 utilities, as compared to 36 in 2006. No studies were found to estimate the total number of customers served by RTP and CPP tariffs.

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[3]Barbose G, C Goldman, and B Neenan. 2004. *A Survey of Utility Experience with Real Time Pricing.* LBNL-5438. Prepared by the Ernest Orlando Lawrence Berkeley National Laboratory for the U.S. Department of Energy, Berkeley, California.
[4]Barbose et al. 2004.

Table M.1.1. Number of Entities Offering and Customers Served by Dynamic Pricing Tariffs[5]

Method of Pricing	Number of Entities	Customers Served	
		Number	Share of Total
Real-Time Pricing	100		
Critical-Peak Pricing	88		
Time-of-Use Pricing	315	1,270,000	1.1%

Interviews were conducted for this report with 21 companies meeting an annual peak demand of 150,000-175,000 megawatts and 0.8-1.2 billion megawatt hours of generation served. The companies were asked two questions relevant to dynamic pricing. The first question asked respondents: Do you have dynamic or supply-based price plans?

- Seven companies (35 percent) indicated no dynamic price plans were in place.
- Twelve companies (60 percent) indicated they had TOU plans.
- Three companies (15 percent) offered CPP plans.
- Seven companies (35 percent) indicated they had both dynamic price plans and the ability to send price signals to customers.

The companies were also asked whether their utility had automated response-to-pricing signals for major energy-using devices within a premise. The utility respondents indicted:

- Nine companies (45 percent) indicated there were none.
- Eight companies (40 percent) indicated that automated price signals for major energy-using devices were in the development stage.
- Three companies (15 percent) indicated that a small degree of implementation (10-30 percent of the customer base) had occurred.

When RTP tariffs were initially offered in the 1980s, customers were typically charged a single, hourly-varying price quoted on a day-ahead basis. The prices for generation, transmission, distribution and ancillary services were bundled into a single price. Rate structures were designed to be revenue neutral. Customers, however, were not entirely shielded from price volatility. Customers included in early RTP programs were medium and large commercial and industrial customers.

In the 1990s, RTP programs shifted increasingly toward a two-part system where customers faced standard pricing up to a customer baseline load (CBL) established on historical consumption patterns and a higher peak price for power purchased in excess of CBL levels. Load reductions below CBL levels resulted in a bill credit. In recent years, the CBL two-part design has become less common and utilities have shifted towards greater retail competition and have offered unbundled RTP tariffs with day-ahead notification. The programs target all commercial and industrial customers and, on a pilot basis, some residential customers.

[5]FERC 2008.

While RTP tariffs have evolved in recent years, programs in many states are not being actively promoted or are in jeopardy of being discontinued. In a recent survey of utilities with voluntary RTP tariffs, 38% indicated that the programs would continue but were not being actively promoted and 28% were in the process of phasing the voluntary tariffs out.[6]

TOU tariffs have gained momentum in recent years. In a survey completed in 1994, the Electric Power Research Institute (EPRI) identified 80 TOU programs with over 500,000 participants. As noted in Section 2.0, the number of customers participating in TOU programs in 2008 had more than doubled relative to 1994 levels, and now has nearly reached 1.3 million. CPP tariffs are not as common in the United States. The first major CPP program was implemented by Gulf Power in 2000. The CPP tariff has recently gained momentum due to the price spikes experienced between 1998 and 2001; however, a recent survey of demand-response and advanced-metering programs identified only 88 utilities offering CPP tariffs.[7]

No forecasts of dynamic-pricing-program penetration were found at either the utility or customer levels. One study, however, did effectively estimate the potential of pricing programs to reduce peak demand between 2008 and 2030. The study, which was sponsored by EPRI and the Edison Electric Institute,[8] estimated that 37 percent of the growth in electricity sales (419 TWh) between 2008 and 2030 could be offset through energy-efficiency programs, and 52 percent of peak-demand growth (164 GW of capacity) could be offset by a combination of energy-efficiency and demand-response programs. More specifically, approximately 2,800 MW of peak demand could be offset by 2010 through price-responsive policies, approximately 14,000 MW of peak demand could be offset through price responsive policies by 2020, and approximately 25,000 MW could be offset by 2030. The majority of the price-response benefits are forecast to take place in the residential sector (11,000 MW, or 44% of the offset in 2030), with the commercial (8,400 MW, or 34% of the offset in 2030) and industrial (5,700 MW, or 23% of the offset) sectors trailing behind.

M.1.3.1 Associated Stakeholders

There are a number of stakeholders with an interest in the dynamic pricing of electricity:

- Regulatory agencies considering AMI business cases and dynamic pricing programs.
- Residential, commercial, and industrial end users who could benefit financially through the deployment of RTP programs, but must overcome their aversion to risk while processing sufficient information to fully understand the benefits and complexity of dynamic pricing programs.
- Electric-service retailers who need to carry out dynamic pricing programs. They need access to wholesale markets that allow them to structure incentive programs to consumers that offer them the means for a viable business model. They desire a level of consistency across the nation so the service offering can be replicated and efficiencies shared.

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[6]Barbose et al 2004.
[7]FERC 2008.
[8]Rohmund I, G Wikler, A Furuqui, O Siddiqui, and R Tempchin. 2008. "Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030)." In *ACEEE Summer Study on Energy Efficiency in Buildings.* American Council for an Energy-Efficient Economy, Washington D.C.

- Distribution-service providers who could use dynamic-pricing adders to address capacity issues, delay construction of marginally-needed generators, increase reliability, and utilize their assets more fully.
- Balancing authorities and reliability coordinators who could use dynamic prices to mitigate congestion issues, and address planned or unplanned shortfalls in available generation capacity.
- Wholesale electricity traders and market operators who can use price elasticity to balance supply and demand, providing for a more responsive energy market.
- Products and services suppliers who are interested in providing the metering, communications, and interfaces with demand-side automation to support dynamic pricing programs.
- Standards organizations, which need to attract stakeholders to develop and adopt standards for the interfaces between technologies being selected to support dynamic pricing programs.
- Policy advocates, including environmental organizations, who can benefit from dynamic pricing to provide alternatives for new-generation power plants and transmission, and consumer groups that can mitigate price increases.
- Policy makers who see dynamic pricing as a way to foster competitive markets and manage load while reducing the need to expand existing generation, transmission, and distribution infrastructure. They are concerned that consumers are treated equitably and will be better off with dynamic pricing than with the traditional flat-rate tariff.

M.1.3.2 Regional Influences

States with voluntary RTP tariffs as of 2003 are indicated in Figure M.1.2. Most of these states are located in the Midwest and along the East Coast, though there were three utilities in California offering voluntary RTP programs. As of 2005, there were 10 utilities offering mandatory or default RTP tariffs in the five aforementioned states that had authorized deployment of RTP tariffs – New Jersey, Maryland, Pennsylvania, New York, and Illinois.

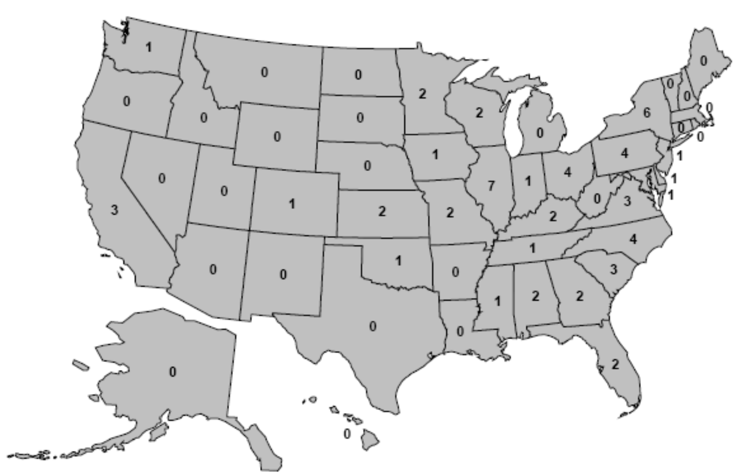

Figure M.1.2. The Number of Utilities by State Offering Voluntary RTP Tariffs in 2003[9]

[9]Barbose et al. 2004.

There are five utilities that account for 96 percent of the customers enrolled in CPP programs: Gulf Power Company of Florida (6,878 enrolled customers), Cass County Electric Cooperative of North Dakota (2,892 enrolled), Southern California Edison Company (462 enrolled), San Diego Gas and Electric (230 enrolled), and Pacific Gas and Electric of California (121 enrolled). The majority of customers enrolled in TOU rate programs are served by IOUs located in the North American Electric Reliability Council-defined Reliability First Corporation (RFC) and Western Electricity Coordination Council (WECC) regions. The RFC region is located in the Eastern United States, stretching from Indiana to New Jersey. The WECC region incorporates most of the Western United States from Montana to Arizona and all states to the West.

M.1.4.0 Challenges to Deployment

There are a number of technical and business/financial barriers to implementing dynamic pricing in the energy sector as outlined in the remainder of this section.

M.1.4.1 Technical Challenges

Technical barriers include those related to AMI and other infrastructure requirements and the need to update billing systems. Utilities must be able to measure usage according to the programs offered, communicate pricing information, and update billing systems prior to deploying variable pricing programs.

M.1.4.2 Business and Financial Challenges

Financial and customer-perception barriers include the following:

- There are significant costs to service providers when installing AMI and updated billing systems. Regulatory recovery of these costs can be a contentious issue. Focusing on large industrial customers and commercial buildings reduces the cost on a per-MW basis.
- The regulated retail market can be a challenge to third-party electricity aggregators and service providers who desire access to customers and dynamic pricing markets that can support viable business plans.
- Quantitative assessments of customer responsiveness to prices are limited. Thus, impacts on service provider financials are not well understood prior to program deployment.
- There may be a self-selection bias in voluntary programs as customers who use less power during peak periods are more likely to enroll in the program, thus making less impact on load participation.
- Customers are not typically interested in complex dynamic pricing programs that must be monitored on an hourly or daily basis. Participation in most voluntary RTP programs has declined in recent years. However, with installation of automated controllers, or automated agents, customers could anticipate and take advantage of price changes to reduce their energy costs.
- Energy consumers are often averse to risk, and the assistance now offered by most service providers to protect them from price volatility may be seen as inadequate.

M.1.5.0 Metric Recommendations

Future reports should consider breaking down the metric by customer-type (e.g., residential, industrial, commercial) to provide greater clarity with respect to the in-roads made by tariff type by customer class.

Metric #2: Real-Time System Operations Data Sharing

M.2.1.0 Introduction and Background

A grid that is "smart" engages information technology in the operation of the transmission grid as much as it does in the distribution network. The lifeblood of any smart-grid network is inherently the data and information that drive the applications that, in turn, enable new and improved operational strategies to be deployed. Data collected at any level of the system, from customer metering to distribution, transmission, generation, and market operations, may be pertinent to improving operations at any other level. Thus, sharing data in a timely fashion, approaching real-time, with all those with a need or right to know, is an essential ingredient of a smart grid.

This section defines a metric for increased levels of real-time data sharing. *Real-time* here means operational updates on time scales that may vary from sub-second to a few minutes. For reasons discussed here, the metric focuses on sharing data between parties at the level of bulk transmission grid operations, as opposed to sharing information within a utility, or for engaging demand response or operating distributed generation and storage.

At the distribution-system level, such information includes giving consumers access to consumption data from smart meters so they can use it for demand- and energy-management purposes, for example. Similarly, there may be other information from utility operations that would be relevant to consumers or other third parties acting at the distribution level, such as demand-response aggregators and operators of distributed generation or storage. However, the barriers to this type of information sharing are more procedural and contractual in nature. Other metrics in this report provide indicators of smart grid progress in these areas (e.g., Metrics 5, 6, 7, 9, 11, and 12). Also, within an electricity service provider's operations footprint, it can be reasonably assumed that data are shared, or could be shared, to the extent required to maintain system stability and reliability, within statutory limits separating transmission operations and wholesale-power-marketing activities.[10] That is, the "right to know" within the utility is implicit, and sharing data within the utility is limited primarily by the difficulty and cost of connecting applications to sensor networks and databases.

A *balancing authority* (BA; formerly known as a control area) is defined by the NERC functional model as an entity that regulates system frequency and performs other coordination activities based on field measurements and external data from neighbors and the appropriate reliability coordinator (RC). BAs must maintain the grid's physical integrity and adhere as closely as possible to the agreed-upon schedule for dispatch of generation, imports, and exports. RCs are needed to coordinate the actions of BAs to maintain overall system reliability. The transmission grid has been increasingly utilized to transfer wholesale power long distances, something which neither its physical design nor its management systems were built to support. Two wide-area blackouts in the western interconnection in 1996[11] and the

[10]Federal Energy Regulatory Commission. FERC Order No. 888. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities.* Accessed November 3, 2008 at http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp (Last updated May 25, 2006).
[11]North American Electric Reliability Council. 2002. *Review of Selected 1996 Electric System Disturbances in North America*. Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731. Accessed November 3, 2008 at http://www.nerc.com/files/disturb96.pdf (undated webpage).

2003 blackout in the eastern interconnection[12] showed how problems that originated in one area could cause blackouts in other widely dispersed areas, and with no way for the adjacent operators to see the problem coming or limit the damage of the disturbance. To remedy this, there is strong movement to improve wide-area reliability coordination. The metric developed here focuses on the volume of data shared by BAs with RCs. The volume of data shared can indicate the comprehensiveness of their reliability view and analyses.

Beyond simply sharing information upward with RCs, a need for increasing the *situational awareness* of the BAs themselves was identified in the 2003 blackout investigation.[13] BAs already share some SCADA information bilaterally with their neighbors about the status of their grid assets. However, measuring the volume of this data sharing is difficult without significant effort.

If the data shared with the RCs to provide a regional view are exchanged back to the BAs, it would provide another mode of data sharing that could accomplish the same result or improve it. More timely and regionally comprehensive model and data exchange would allow BAs to conduct their analyses with greater accuracy. A metric for this topic should include reverse sharing of data (or state estimates derived from resolving the data with the physical topology of the grid) from the RCs with the BAs, i.e., full two-way flow of such information.

Phasor data, i.e., synchrophasor measurements obtained from phasor measurement units (PMU), contains high-time-resolution (typically 30 samples per second) measurements of voltage and current waveforms, time synchronized and time stamped using the satellite-based global positioning system. Phasor data supplements SCADA data. The current applications that use phasor data do not require the same comprehensive coverage provided by SCADA. Instead, data from a relatively sparse network of PMUs are being used to provide situational awareness and early warning of stability and reliability issues as well as post-event forensic capabilities for wide areas of the grid. To contribute to situational awareness, this information must also be shared.

Ultimately, more comprehensive reliability analysis based on broadly sharing data may lead to increased utilization of wide-area control schemes and remedial action schemes, and allow them to be adjusted dynamically depending on the state of the grid. This is a beginning of the self-healing functions that have long been a key objective of the smart grid at the transmission-grid level.

M.2.2.0 Description of the Metric and Measurable Elements

This section addresses (1) the extent of sharing of SCADA information from BAs upward to RCs and back to the BAs, and (2) the extent of institutionalized data sharing of synchrophasor data among utilities, BAs, and RCs.

(Metric 2.a) Total SCADA points shared per substation (ratio)—the number of SCADA transmission grid measurement points from grid assets that are shared by BAs with RCs, plus the number of SCADA measurement points shared by the RCs with BAs, divided by the number of substations:

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[12]U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations.* Accessed November 3, 2008 at http://www.pi.energy.gov/powertaskforce.html (undated webpage).
[13]U.S.-Canada Power System Outage Task Force. 2004.

(Total_Points_BAs→RCs + Total_Points_RCs→BAs) / Total_Substations

- *Total_Points_BAs→RCs*: the number of transmission-grid measurement points (e.g., voltage, power flow, etc.) from grid assets routinely shared by a control area with the RC responsible for supervising its region. The greater the number indicates the more complete a picture of grid status is being shared with the RC. *Measurement point* corresponds to a sensor, not it's time-series output, i.e. each sensor counts as "one" regardless of the frequency of the measurements it records or that are shared. The phrase "from grid assets" is intended to prevent duplicate counts of a single measurement point to which adjoining BAs jointly have access and both forward to the RC.

- *Total_Points_RCs→BAs*: the number of transmission-grid measurement points routinely shared by the RC back to the BAs under its purview. The RC may share a set of data points with each of the BAs; each measurement point shared counts as "one" regardless of how many BAs receive it. Again, this is to prevent counting the measurement point once for each of many Bas that may receive it. This definition presumes that if a measurement point is shared with one BA, it would be available to all of them. By adding the measurement-point data shared in each direction, there is an implicit "perfect score" for a measurement point of exactly two, representing full two-way data sharing. If state estimates based on the data are shared by the RC, instead of raw data, then this should be counted as full two-way data flow.

- *Total_Substations:* The denominator of the metric is defined as the total number of utility substations within the BAs supervised by the RC. This is chosen instead of the number of busses used to model the system, because it is less ambiguous.

The metric can be used at any level of the grid, but should be computed and reported for each interconnection in the U.S. and for the U.S. grid as a whole.

(Metric 2.b) Fraction of transmission-level synchrophasor measurement points shared multilaterally (%) — the fraction shared is the number of phasor measurement points routinely shared via a multilateral institutional arrangement divided by the total number installed in a region of the power grid.

Total_Phasor_Measurment_Points_Shared / Total_Phasor_Measurement_Points

- *Total_Phasor_Measurement_Points:* One count for each measurement from each PMU or equivalent installed on the grid at voltage levels above distribution voltage. Many new grid-sensing, control, and protection devices have PMU capabilities built in; if they are installed on the distribution system, they would not be counted.

- *Total_Phasor_Measurement_Points_Shared:* One count for each measurement from each transmission-level PMU or equivalent that is routinely shared via a multilateral institutional arrangement. This intentionally excludes bilateral arrangements because they are difficult to track, are less likely to persist over time, and may not be comprehensive.

Metric 2.b can be derived for any region of the grid, but will be computed and reported for each interconnection in the U.S. and for the U.S. grid as a whole.

M.2.3.0 Deployment Trends and Projections

A recent survey by Newton-Evans Research[14] indicates there is significant sharing of measurement, analysis, and control data from utility control systems for transmission and distribution (SCADA, energy management systems – EMS, and distribution management systems - DMS) with other grid entities including regional control centers and other utilities. The results of this survey of 30 U.S. investor-owned utilities, 46 public power utilities, 51 U.S. rural electric cooperatives, and 18 Canadian utilities in North America appear in Figure M.2.1, which shows the current and projected integration of EMS/SCADA/DMS systems to a variety of other control systems. It indicates that currently 28% have linkages with ISO/RTOs and 21% have linkages with regional control systems. By 2010, an additional 4% and 2% expect to have such linkages, respectively. These values capture part of the intent of Metric 2.a, but do not indicate the full extent or comprehensiveness of the data being shared. The survey also indicates that 60% of the control centers in North America have linkages with other utilities, which indicates the extent of bilateral data exchanges.

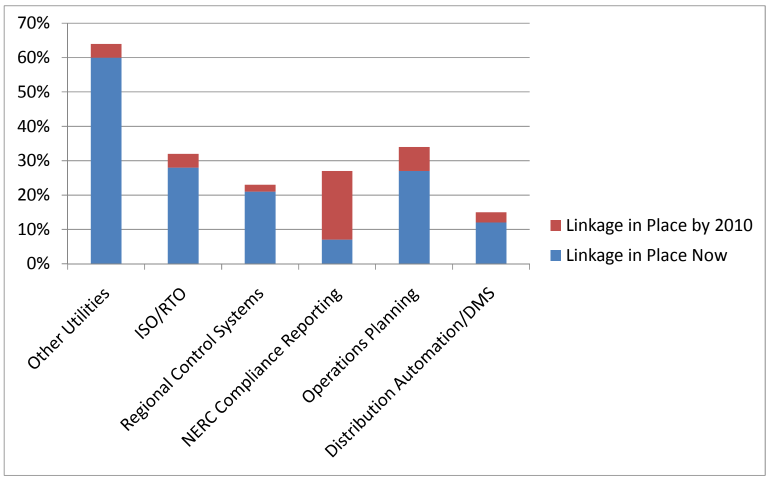

Figure M.2.1. Current/Future Plans for Connecting EMS/SCADA/DMS Systems to Other Data Systems[15]

The data for Metric 2.b was obtained from the participants of the North American SynchroPhasor Initiative (NASPI), a joint DOE-NERC effort to facilitate and expand the implementation of phasor technology for enhancing power system situational awareness and reliability. The results for Metric 2.b are shown in Table M.2.1. The table shows the total number of PMUs installed, the total number shared on a multilateral basis through institutions such as NASPI, and the fraction of transmission-level phasor-measurement points shared multilaterally (Metric 2.b) for each North American interconnection. Only the Eastern Interconnection currently has a multilateral data sharing agreement, which involves 86% of the 104 PMUs. For the entire North American transmission grid, 51% of the installed 175 PMU data points are shared.

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[14]Newton-Evans Research Company. 2008. *Market Trends Digest*. Newton-Evans Research Company, Endicott City, Maryland. Accessed November 11, 2008 at: http://www.newton-evans.com/mtdigest/mtd3q08.pdf
[15]Newton-Evans 2008.

Table M.2.1. Fraction of PMU Data Points Shared in the North American Transmission Grid

Interconnection	PMUs Installed	PMUs with Multilateral Data Sharing Agreements	Fraction Shared Multilaterally
Electric Reliability Council of Texas	0	0	(NA)
Eastern Interconnection	104	89	86%
Western Interconnection	61	0	0%
Quebec Interconnection	10	0	0%
Total, North American transmission grid	**175**	**89**	**51%**

The interviews with 21 electricity providers done for this report asked a set of questions that looked at data sharing, primarily within the utility enterprise. The results are shown in Figure M.2.2. Perhaps the most telling response is that 40% of respondents agreed that "new information is flowing across functions and systems."

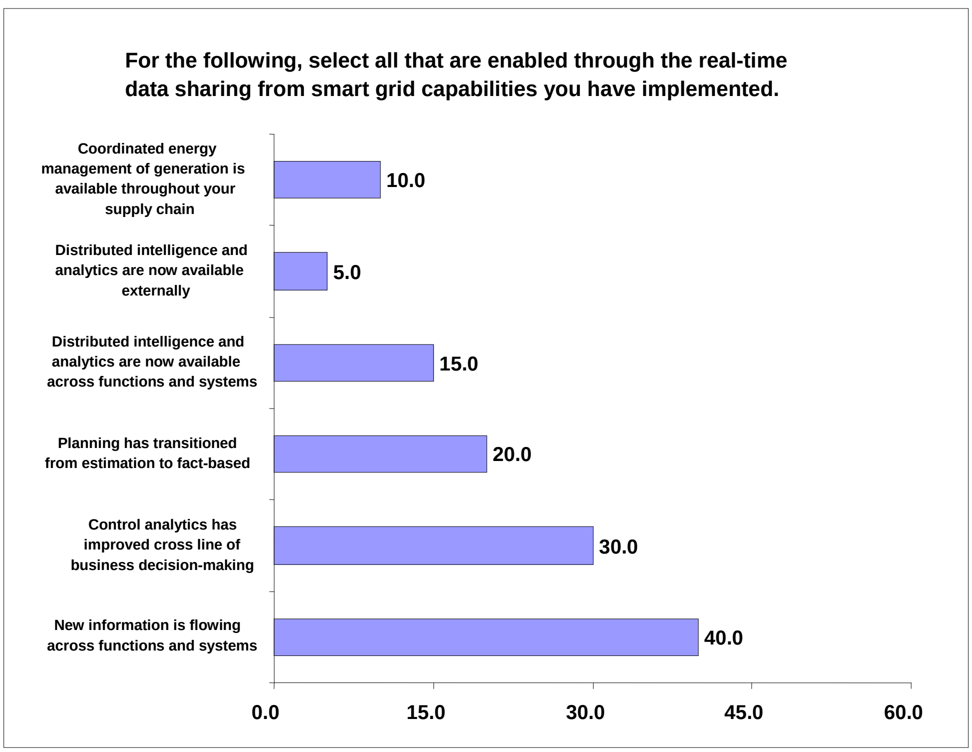

Figure M.2.2. Summary of Interviews Regarding Real-Time Data Sharing

M.2.3.1 Stakeholder Influences

Aspects of the U.S. electrical transmission system are regulated mostly on both a federal level (reliability and interstate commerce) and at the state level (siting, prudency of investment, rate recovery). Input and planning for the transmission infrastructure is conducted, in increasing levels of detail and ultimate authority, by groups of state/regional governments, regional RCs, regional transmission operators or independent system operators (where they exist), and the utilities themselves. The planning and operation of the transmission grid involves the participation of a very large number of stakeholders as well.

Among the stakeholders indentified in Section 1.3 the following have special interest in transmission-level real-time data sharing (Metrics 2.a and 2.b):

- Transmission providers and BAs: The metrics provide a benchmark for transmission providers and BAs sharing information that raises their situational awareness, can increase reliability, and may eventually result in wide-area control schemes that help realize the goal of a self-healing grid.
- Reliability coordinators including NERC: The metrics provide a benchmark of progress toward increasing sharing of data by NERC's constituents. Data sharing helps NERC achieve its reliability goals. The existence of the metrics themselves could serve as motivation toward institutionalizing data-sharing mechanisms (especially for phasor data).
- Products and service providers: Increased sharing of transmission data over wide areas opens up opportunities to develop new analysis applications driven by the data, which in turn may help promote sales and installation of phasor-measurement-capable devices.
- Local, state, and federal energy policy makers; policy advocates: The existence of the metrics helps them focus on and drive the institutionalization of data-sharing mechanisms.

Other stakeholders with less direct interest include:

- Generation and demand wholesale electricity traders/brokers: They benefit from the more reliable electric grid that sharing data enables because market-based dispatch is less often disrupted by operational contingencies.
- Distribution-service providers: They benefit indirectly because the more reliable bulk-power system that data sharing will enable causes less disruption to their distribution systems.
- Electric-service retailers and end users: They benefit from being able to offer and obtain, respectively, more reliable electric service.

M.2.3.2 Regional Influences

The metrics are measured for each interconnection because of the strong regional differences associated with the size and governing institutions for each of the three interconnections. The Electric Reliability Council of Texas (ERCOT) is by far the smallest of the three in terms of population, number of substations, load served, and geographic area. It also has the most unified institutional arrangement, with ERCOT acting as the regional transmission operator and planner, the market operator, and the RC. As such, it has great authority to engage constituent utilities in integrating their transmission data.

The Western Interconnection is nearly as large in extent as the Eastern Interconnection, yet serves a significantly smaller population scattered mostly in widely-separated pockets. It's widely-separated population centers and generation causes it to have special problems with low-frequency oscillations and dynamic stability, issues that led to the 1996 blackouts, and have driven it to be an early adopter of data-sharing arrangements. An interconnection-wide coordination council (the Western Electricity Coordinating Council[16] [WECC]) was created in 2002 with a focus on wide-area issues associated with reliability. Of particular note with respect to Metric 2.b, members of the Western Interconnection were the early pioneers for phasor data collection and sharing in the 1990s (albeit it remains bilateral rather than institutional).

The WECC is now engaged in constructing a fully-detailed operational model of the entire interconnection, so that interconnection-wide state estimation and contingency analysis programs can be performed. This is an example of how data sharing enables increased levels of situational awareness that should result in higher reliability. This development will drive increased data sharing that should result in higher values for Metric 2.a in the future.

The Eastern Interconnection with its large area, dense population, and closer proximity of population centers to generation, has thirteen RCs compared to the Western Interconnection's three. The eastern grid is relatively "stiff" in that it does not exhibit the oscillatory behavior that the West Interconnection does. The 1996 and 2003 blackouts clearly showed that such events can extend beyond even the larger areas of a single RC, yet the Eastern Interconnection does not have an interconnection-wide institution charged with reliability like the WECC that can help drive data sharing. Partly as a result of the 2003 blackout, however, an Eastern Interconnection Phasor Pilot (EIPP) project was established that has pioneered phasor data sharing with the notion of phasor data concentrators that collect and archive all of it. The EIPP is the precursor of NASPI, which is attempting to formally institutionalize data sharing, among its other objectives.

M.2.4.0 Challenges

Technical, business, and policy challenges all complicate the use "real-time data exchange" as a metric of smart grid evolution.

M.2.4.1 Technical Challenges

The principal technical challenges involved with data sharing at the transmission level involve the level of effort to identify, configure, and maintain the data to be exchanged between parties. Standard protocols exist for inter-control center site data exchange and phasor data exchange. Most suppliers of control center systems support these standards; however, complete, unambiguous interoperability requires significant processing and testing. Besides the data exchange protocols, common naming conventions and unambiguous identity services would make integration and maintenance easier. Software interfaces that support publishing, and interrogation services that are consistent with cyber security and information privacy policies (see business and policy challenges below) would reduce the manual labor involved to support data sharing.

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[16]Western Electricity Coordinating Council. 2008. *Western Electricity Coordinating Council Mission and 2007 Goals*. Accessed November 3, 2008 at http://www.wecc.biz/documents/library/publications/Mission%20Statement%20-%202007%20Goals.pdf (undated webpage).

Situational awareness and system operations applications, such as state estimation, also require the sharing of system modeling data. Power system models are complex and continually evolve as parts of the system are taken out of service or new construction is added. Ownership and responsibility rights are also continually changing and require periodic updates. Data sharing initiatives can be put on hold or discarded because the parties involved are not willing to support and exchange the requisite system models. Agreement on technical approaches and services can help reduce model maintenance and the burden of keeping neighbor model consistent; however, the problems are complex to explain, and therefore, often underappreciated by the organizations involved.

M.2.4.2 Business and Financial Challenges

There are procedural, business and privacy issues that hinder sharing of data and information collected by a utility with peers and higher-level grid RCs. This applies to SCADA, phasor measurements, and derived data from application programs. Certain circumstances may require sharing of information with non-grid entities such as emergency-response centers or state and federal government agencies charged with public safety, homeland security, or national defense. Formalized mechanisms for data exchange would simplify data collection for these metrics.

The inhibitions to sharing such data include:

- competitive intelligence – the value of operational information could be used in corporate takeovers, service-territory takeovers, change to municipal service by cities or utility districts ("municipalization"), or competition to serve areas of growth that do not currently have service;
- market intelligence – merchant generators, power marketers, and aggregators may be able to glean information that enhances their bidding strategies in deregulated wholesale markets, and regulated utilities may want to inhibit competitors from serving load in their service area;
- second guessing and prudency reviews – from peers, competitors, federal and state governments and regulators, and consumers, about operational decisions;
- financial penalties – associated with outages or unsafe operating conditions, in the form of fines from reliability-monitoring entities for operating outside guidelines or specifications, lawsuits from customers for damages from outages, and reduced incentive payments from state utility regulators;
- data security – concern that shared information may not be kept secure and therefore could highlight physical or control-system vulnerabilities that could be exploited to the detriment of national security.

These inhibitions are particularly significant when operational data must be shared among peers, particularly utilities and BAs.

M.2.5.0 Metric Recommendations

The results for Metric 2.a have not yet been collected. The intention is to gather this information from key industry stakeholders, such as the Data Exchange Working Group or the Reliability Coordinator

Working Group, both under the NERC Operating Committee. The intent is to create a table that shows the total measurement points shared by BAs with the RCs, by RCs with the BAs, the total number of utility-owned substations in each interconnection, and the Number of shared SCADA points per substation node (Metric 2.a). These are broken down within each interconnection by RC, and aggregated to the U.S. power grid. This should be done as soon as possible so that a baseline is established for future versions of this report.

Bilateral data exchanges are not formally recognized in this metric, as defined, but could be incorporated in this framework if desired or needed. For example, if the RC did not deliver data from measurement points to BAs, but instead the BAs in a region agreed to universally share a set of measurement points with each other through another arrangement, this would accomplish the same end, and each point shared should be counted as "one."

Since metrics have inherently subjective qualities, interviews with individuals within utilities could provide a more accurate view of the situation. Future interviews conducted for this report should develop questions that more directly align with the BA/RC data sharing metrics expressed here.

An analogous metric might be developed for data exchange with customers. One such metric could be constructed around whether customers have real-time access to their meter data. For metrics focused on the issue of whether sufficient information is exchanged with customers so they can participate, it can be argued that most customers would not be able to respond to such questions in legitimate fashion. Perhaps technology vendors and aggregators could represent customers in this regard, with a more solid technical basis. It should be noted that expectations for data exchange with customers will tend to grow over time. An example of this is the emerging desire to provide ancillary services with customer demand response, which at present requires intensive and timely data exchange on 4-second intervals.

For Metric 2.a and 2.b, it should be recognized that data exchange at the bulk grid/transmission level is only a means to an end. The end result is situational awareness leading to increased reliability and eventually a self-healing grid. Exchanging data does not accomplish anything, in and of itself. If metrics could be developed that better capture that the data is being *used,* which applications it was being used *for*, what the *geographic/topological scale* of the analyses are, these would better capture the intent of data sharing metrics for the transmission grid. Similarly, we have made the simplifying assumption that exchange up to the RC and back to the BAs has the most merit as an indicator of progress. But, this avoids grappling with the issue of whether the RC is the right scale for situational awareness, or whether a broader scope of awareness needs to exist.

Metric #3: Standard Distributed Resource Connection Policies

M.3.1.0 Introduction and Background

The increasing presence of backup generation among utility customers has led to various efforts for standardizing the process of interconnecting these resources to the grid. The Carnegie Mellon Electricity Industry Center reports that there are now about 12 million backup generators in the United States, representing 200 GW of generating capacity that is growing at a rate of 5 GW per year.[17] Utilities that facilitate the integration of these resources and use them effectively can realize enormous cost savings over the long term. Distributed resources can be used to help alleviate peak load, provide needed system support during emergencies, and lower the cost of power provided by the utility.

The cost, time lag, and onerous review process associated with interconnecting distributed resources to the grid are often cited as major barriers to further adoption of distributed energy resources (DER). Federal legislation attempting to deal with this issue has emerged in progressively stronger language, culminating in the Energy Policy Act of 2005 (EPACT 2005),[18] which requires all state and non-state utilities to consider adopting interconnection standards based on IEEE Standard 1547. IEEE 1547, which was published in 2003, looks strictly at the technical aspects of distributed-generation interconnection, providing a standard that limits the negative impact of these resources on the grid.[19] In part to address some of the permitting aspects of interconnection, the FERC issued FERC Order 2006, which mandated that all public utilities that own transmission assets provide a standard connection agreement for small generators (under 20 MW).[20] This will provide expedited permitting for many customers using distributed generation; however, it is up to each state and utility to determine how to define and implement these rules.

M.3.2.0 Description of Metric and Measurable Elements

(Metric 3) The percentage of utilities with standard distributed resource interconnection policies

The topic also discusses the commonality of such policies across utilities.

M.3.3.0 Deployment Trends and Projections

While compliance with FERC Order 2006 is mandatory for public utilities that own transmission assets, other utilities have come under similar legislation at the state level. The progress of these laws, however, has been fairly slow. Even states complying with the mandatory FERC order have taken over

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[17]Gilmore E and L Lave. 2007. *Increasing Backup Generation Capacity and System Reliability by Selling Electricity during Periods of Peak Demand*. 26th USAEE/IAEE North American Conference, September 16-19, 2007. Carnegie Mellon Electricity Industry Center. Accessed November 24, 2008 at http://www.usaee.org/usaee2007/submissions/Presentations/Elisabeth%20Gilmore.pdf

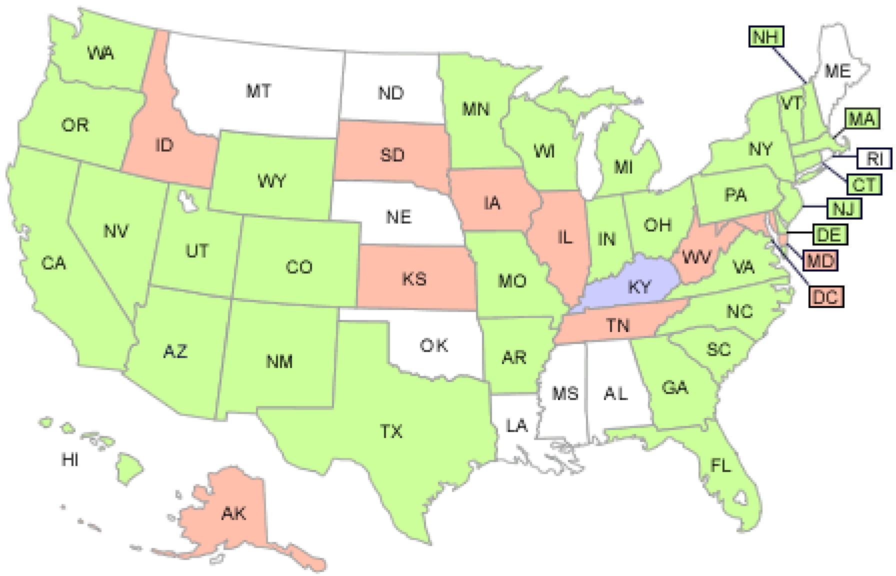
[18]45 USC 15801 et seq. 1986. *Energy Policy Act of 2005*. Public Law 109-58, as amended. Accessed November 26, 2008 at http://www.oe.energy.gov/DocumentsandMedia/EPACT05ConferenceReport0.pdf

[19]Cook C and R Haynes. 2006. *Analysis of US Interconnection and Net-Metering Policy*. North Carolina Solar Center, North Carolina State University, Raleigh, North Carolina. Accessed November 24, 2008 at http://www.ncsc.ncsu.edu/research/documents/policy_papers/ASES2006_Haynes_Cook_.pdf

[20]Federal Energy Regulatory Commission (FERC) Order 2006-A. 2005. *Standardization of Small Generator Interconnection Agreements and Procedures (Order on Rehearing)*. Docket Number RM02-12-001.Washington, D.C. Accessed November 24, 2008 at http://www.caiso.com/14ea/14ead07a4660.pdf

two years to enact these relatively simple rules. States that have taken aggressive action on distributed generation have tended to do so for other reasons, such as meeting renewable portfolio standard requirements.

In February 2008, the Environmental Protection Agency (EPA) did a study of the 50 states and the District of Columbia, assessing their standards for interconnection. They found 31 states with standard interconnection rules for distributed resources, and 11 additional states in the process of developing rules. Of these, the EPA found that 55% had standard interconnection forms, 29% had simplified procedures for smaller systems, 35% had a set timeline for application approval, and 45% had larger system size limits (over 10 kW for residential and over 100 kW for commercial systems).[21] Figures M.3.1 and M.3.2 show the EPA results by state.



Policy in place:
AR, AZ, CA, CO, CT, DE, FL, GA, HI, IN, MA, MI, MO, MN, NH, NJ, NM, NY, NV, NC, OH, OR, PA, SC, TX, UT, VT, VA, WA, WI, WY

Action is pending/possible:
AK, DC, IA, ID, IL, KS, MD, SD, TN, WV

Some elements of policy are in place:
KY

Policy not in place:
AL, LA, ME, MS, MT, NE, ND, OK, RI

Figure M.3.1. State Interconnection Standards[22]

By multiplying the percentages above by the number of utilities in each state, it is estimated that roughly 61% of utilities have a standard interconnection policy in place, and that 84% of utilities either have a policy in place or will have one soon based on pending legislation or regulation.[23]

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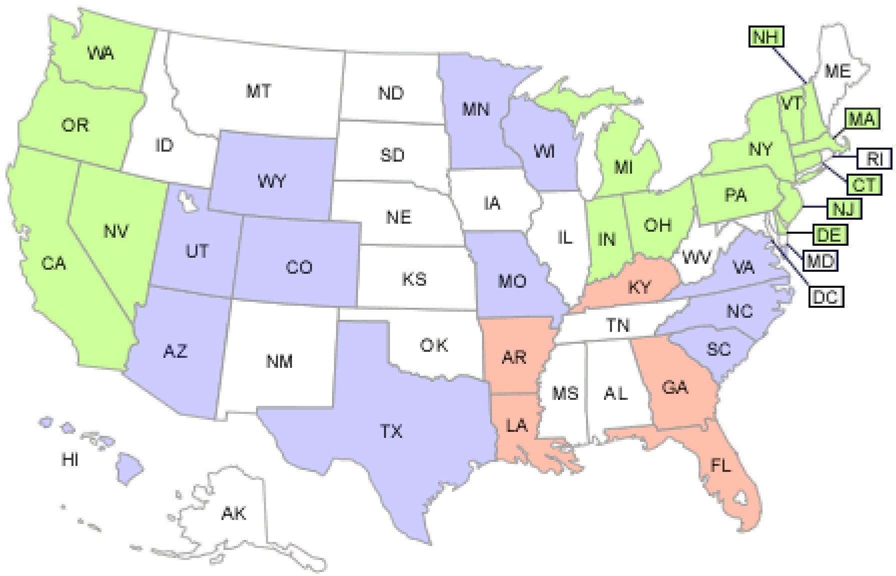
[21]U.S. Environmental Protection Agency (EPA). 2008. *Interconnection Standards*. Combined Heat and Power Partnership (CHP), U.S. Environmental Protection Agency, Washington, D.C. Accessed November 24, 2008 at http://www.epa.gov/chp/state-policy/interconnection.html

[22]EPA 2008. *Interconnection Standards.*



Favorable Interconnection Standards:
CA, CT, DE, IN, MA, MI, NH, NJ, NY, NV, OH, OR, PA, VT, WA
Unfavorable Interconnection Standards: AR, FL, GA, KY, LA
Neutral Interconnection Standards: AZ, CO, HI, MN, MO, NC, SC, TX, UT, VA, WI, WY
No policy in place: AL, AK, DC, ID, IA, IL, KS, ME, MD, MS, MT, NE, NM, ND, OK, RI, SD, TN, WV

Figure M.3.2. Favorability of State Interconnection Standards[24]

The EPA's study based its criteria for favorability on whether or not standard forms were in place, time frames for application approval, insurance requirements, distributed-resource sizes allowable, and interconnection study fees. With these factors considered, only 15 states were classified as having "favorable" interconnection standards, with 27 states either being "favorable" or "neutral." The fact that there are five states with unfavorable policies towards distributed generation is also cause for concern, although it is worth noting that that these states are all in the southeast region of the United States.

There are currently about 10 states with new DER interconnection standards under consideration (AK, DC, IA, ID, IL, KS, MD, SD, TN, WV). Most projections show increasing deployment of these resources, especially in the commercial sector where power quality and power reliability are becoming issues of increasing concern. A study from the EPRI, for example, estimates that by 2010, 25% of new electric power generation will be in the form of distributed generation.[25] These resources will require smart-grid technologies and new regulations to integrate effectively, but will greatly benefit utilities if used appropriately.

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[23] Energy Information Administration (EIA). 2002. *Contact Information for Electric Utilities by State*. EIA, U.S. Department of Energy, Washington, D.C. Accessed November 24, 2008 at http://www.eia.doe.gov/cneaf/electricity/utility/utiltabs.html
[24] EPA 2008. *Interconnection Standards.*
[25] Dugan R, TE McDermott, DT Rizy, and SJ Steffel. 2001. "Interconnecting Single-Phase Backup Generation to the Utility Distribution System." In *2001 IEEE/PES Transmission and Distribution Conference and Exposition*. Institute of Electrical and Electronics Engineers, Inc., Piscataway, New Jersey. Accessed November 24, 2008 at http://www.ornl.gov/~webworks/cppr/y2001/rpt/112434.pdf

M.3.3.1 Associated Stakeholders

There are a variety of stakeholders that have added their input to various state processes regarding interconnection:

- Distribution-service providers and electric-service retailers, who will ultimately be responsible for managing the grid impact of these resources
- Suppliers of distributed-resource products and services, who would gain significantly from easier interconnection standards
- Regulators and policy makers, who are concerned with how utilities choose to account for the costs of these resources, as well as other related legislation, such as meeting renewable-portfolio-standard requirements
- End users who have distributed resources on their properties and want to tap into the potential benefits of selling power back to the grid

M.3.3.2 Regional Influences

Regional differences in perception of the dangers and benefits of distributed resources have made an impact on where they are deployed. Many of the regional policies that have emerged are driven by a few major state players; their policies are then copied by other states and regions.

- California's progressive distributed-generation interconnection policies place no limits on the size of the resource. This is coupled with strong incentives for renewable sources of energy such as photovoltaic solar panels primarily for the purpose of promoting cleaner alternative power sources and reducing transmission congestion. California's policies have had a strong impact along the west coast.[26]
- New York, which was one of the first states to adopt a standard interconnection policy in 1999, has continued to provide support for distributed generation. Part of the driver for this has been power outages and transmission congestion, which continue to plague much of the state.[27,28]
- The Mid-Atlantic Distributed Resources Initiative (MADRI), representing the utility interests of Delaware, the District of Columbia, Maryland, New Jersey, and Pennsylvania, has been a strong driver of interconnection standards for distributed resources and has proposed a model that has been adopted by many states.[29,30]

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[26] Shirley, W. 2007. *Survey of Interconnection Rules*. The Regulatory Assistance Project. Montpelier, Vermont. Accessed November 24, 2008 at http://www.epa.gov/chp/documents/survey_interconnection_rules.pdf

[27] Brooks, Susanne, Brent Elswick, R Neal Elliott. ca. 2007. *Combined Heat and Power: Connecting the Gap Between Markets and Utility Interconnection and Tariff Practices (Part 1).* American Council for an Energy-Efficient Economy, Washington D.C. Accessed February 6, 2009 at http://txspace.tamu.edu/bitstream/handle/1969.1/5646/ESL-IE-06-05-29.pdf;jsessionid=E3BEDBFE54ED9C979F738211A5592445?sequence=1

[28] Shirley, W. 2007.

[29] Brooks et al. 2007.

[30] Shirley, W. 2007.

- Many states in the Southeast region have been resistant to implementing favorable standards for interconnection (Figure M.3.2). This may be due to regional challenges that must be overcome specifically in those states, which would require special assistance.

M.3.4.0 Challenges to Deployment

The barriers to deployment may begin to fall as more states adopt progressive policies to allow higher penetrations of DER. Significant barriers will remain in certain regions such as the Southeast, where this groundwork has not been done. If climate legislation is passed, it may prove to be a significant barrier to more traditional forms of DER such as diesel reciprocating engines.

M.3.4.1 Technical Challenges

There is still disagreement among some utilities and DER manufacturers about how to handle DER interconnection at high levels of penetration. With low levels of penetration, most utilities consider their distribution systems to be robust enough to handle disturbances in the system and unexpected DER disconnects. At this point, however, the technical specifications for DER are written conservatively, in order to err on the side of safety.[31] For example, most interconnection agreements require DER not to feed back into the system. Protection schemes presume that power is flowing to the customer; however, some utilities, such as Portland General Electric and DTE Energy Company are accommodating DER integration to provide power flow back into the grid.[32]

M.3.4.2 Business and Financial Challenges

Utilities still have difficulty making the business case for distributed resource integration, especially without integrated distribution and transmission planning. While using DER can aid utilities in reducing transmission congestion, these effects are difficult to model and are generally not within the purview of utilities.

M.3.5.0 Metric Recommendations

The investigation for this metric relies almost exclusively on a one-time study of DER interconnection policies. Reliance on a single report for both a definition of what constitutes a standard DER interconnection policy and an estimate of the number of utilities with such policies in place has shortcomings when considering the potential to monitor trends over time. Thus, future smart grid metric reports should give consideration to both defining what constitutes a standard DER interconnection policy and identifying surveys, reports, or other literature that will yield consistent results over a longer time horizon. Also, consideration should be given to assessing the fairness of DER interconnection policies to encourage a level playing field for DER integrators, utilities, and ratepayers. Further, questions should be devised and used during the process of conducting interviews in support of future smart grid metric reports.

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[31] Institute of Electrical and Electronics Engineers (IEEE) 1547. 2003. *Standard for Interconnecting Distributed Resources with Electric Power Systems.* No. 1547, IEEE, New York.
[32] Waligorski, Joseph G. October 2008. *Utility Consortium Project Summary.* DOE RDSI Peer Review Meeting, Red Bank, New Jersey. Accessed February 6, 2009 at https://events.energetics.com/rdsi2008/pdfs/presentations/thursday-part2/4%20%20Waligorski%20GridApps.pdf

Metric #4: Regulatory Recovery for Smart Grid Investments

M.4.1.0 Introduction and Background

Section 1252 of the Federal Energy Policy Act of 2005 (EPAct) outlines policies and objectives for encouraging a smart grid initiative, including the provision of time-based rates to customers and the ability to send and receive real-time price signals. While EPAct outlined objectives for advancing smart-grid concepts, it did not require utility investment in smart grid technologies, nor did it establish or outline a regulatory framework to encourage such investment.

The Energy Independence and Security Act of 2007 (EISA) did authorize incentives for utilities to undertake smart-grid investments. Section 1306 authorized the Secretary of the U.S. DOE to establish the Smart Grid Investment Matching Grant Program, which was designed to provide reimbursement for up to 20 percent of a utility's investment in smart-grid technologies. Section 1306 also outlined what constituted qualified investments and defined a process for applying for reimbursement. Section 1307 encouraged states to require utilities to demonstrate consideration for smart grid investments prior to investing in non-advanced grid technologies. Section 1307 also encouraged states to consider regulatory requirements that included the reimbursement of the book-value costs for any equipment rendered obsolete through smart grid investment. The American Recovery and Reinvestment Act of 2009 allocated funding to help support these EISA programs.

While the primary objectives for implementing a smart grid may encompass environmental, energy-efficiency, and national-security goals, they will be more difficult to reach if utilities are unable to make an effective business case to regulatory agencies. Smart-grid investments often are capital intensive, expensive, and include multiple jurisdictions within a utility's service area. While smart-grid investments can achieve numerous operational efficiencies (e.g., reduce meter-reading costs, require fewer field visits, enhance billing accuracy, improve cash flow, improve information regarding outages, enhance response to outages), such benefits may be difficult to quantify and build into business cases.[33] There is considerable debate among consumer representatives whether smart-grid benefits outweigh the costs.

A survey targeting large-scale AMI utility projects conducted by KEMA found that the average project required a $775 million investment.[34] With such an enormous expense, utilities must be sure that regulatory recovery is feasible, and while the up-front costs of the investment are easy to calculate, the back-end benefits can be difficult to monetize within current regulatory valuation models.

At present, utilities are rewarded under ratemaking frameworks for capital projects and energy throughput. That is, expanded peak demand drives the need for additional capital projects, which increases the rate base. As energy sales grow, revenues increase. Both factors run counter to encouraging smart-grid investments. Thus energy efficiency, demand reduction, demand response, distributed generation, and asset optimization can be discouraged by current regulatory frameworks.[35]

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[33] Mukherjee, J. "Building Models for the Smart Grid Business Case." *EnergyPulse*, April 2008. [Available at: http://www.energypulse.net/centers/article/article_display.cfm?a_id=1721]

[34] McNamara W and M Smith. 2007. *Duke Energy's Utility of the Future: Developing a Smart Grid Regulatory Strategy Across Multi-State Jurisdictions.* Grid-Interop Forum 2007, Paper ID-1. 2007. Accessed November 24, 2008 at http://www.gridwiseac.org/pdfs/forum_papers/155_paper_final.pdf

[35] Anders, S. *Implementing the Smart Grid: A Tactical Approach for Electric Utilities.* Energy Policy Initiatives Center presentation, University of San Diego School of Law, October 15, 2007. Del Mar, CA.

M.4.2.0 Description of Metric and Measurable Elements

(Metric 4) the weighted average (respondents' input weighted based on total customer share) percentage of smart grid investment recovered through rates.

M.4.3.0 Deployment Trends and Projections

The smart-grid interviews conducted for this report included 21 companies. Respondents were asked the following question: What type of regulatory policies (beneficial regulatory treatment for investments made and risk taken) are in place to support smart-grid investment by your utility? Of those interviewed,

- six companies (30.0%) indicated that there were no regulatory policies in place to support smart grid-investment
- four companies (20.0%) indicated there were mandates in place to support investment in smart-grid features, such as smart meters
- three companies (15.0%) indicated there were incentives in place to encourage smart-grid investment
- ten companies (50.0%) indicated that there was some form of regulatory recovery for their smart-grid investments.

Companies were also asked to estimate the percentage of smart-grid investments to date that has been recovered through rate recovery, and compare that total against their expectations for future investments in the smart grid. The service providers interviewed for this report indicated that, on average, they are recovering only 8.1 percent of their investment through rate structures, but predict regulatory recovery rates will expand significantly in the future, ultimately reaching 90.0 percent.

While state regulations have generally not specified outright denial of cost recovery for AMI and smart grid investments, such cost recovery has been limited and the trend appears focused on a small number of concepts:

- trackers—a method that involves the tracking of unpredictable costs incurred by utilities, and allows recovery over a 12-month period. Trackers may be tied to specific projects or broader measures.
- balancing accounts / rate base—balancing accounts enable utilities to identify and recover reasonable and prudent costs through future rate structures when costs are unrecovered due to rate freezes or ceilings. Utilities have also been allowed to build cost recovery into the rate base.
- customer surcharge—a charge allowed by the governing utility commission to recover specific cost elements, such as AMI programs.
- state funding—funding from existing or newly created state accounts.[36]

As noted in Section 2.2, the most common recovery methods are trackers and recovery through rate-base adjustments. As noted in Section 2.0, service providers interviewed for this report indicated that, at present, only 8.1 percent of their investments in smart grid technologies are being recovered through rate adjustments. These utilities, however, also indicated that their expectation is for recovery to expand in the coming years to 90.0 percent.

[36] McNamara and Smith 2007.

Another recent trend enabled by some public utility commissions involves expanding valuation models used to support business cases. Elements considered within these models have, in certain cases, expanded to include societal benefits, such as the reduction of greenhouse gases, wider service offerings, reduction of carbon footprint, customer satisfaction, and increased energy efficiency. Many public utility commissions are also embracing the concept of building system-wide benefits into business cases.[37]

M.4.3.1 Associated Stakeholders

There are a number of stakeholders with an interest in regulatory recovery for smart-grid investments:

- Regulatory agencies considering smart-grid business cases
- Residential, commercial, and industrial customers who could benefit from the deployment of smart-grid technologies, but are wary of the significant costs
- Transmission and distribution service providers and balancing authorities interested in reducing peak demand, enhancing efficiency, and reducing the costs to supply energy
- Policy advocates, such as environmental organizations interested in reducing the need for new power-generation plants
- Policymakers interested in fostering competitive markets and managing load while reducing the need to expand existing generation, transmission, and distribution infrastructure.

M.4.3.2 Regional Influences

There are opportunities for expanded smart-grid investment when sales are decoupled from revenues. When states decouple sales from revenues, energy-efficiency measures, including smart grid, are encouraged. If decoupling encourages energy efficiency, then a concern for consumers is that using less energy should reduce, not increase, electric bills. Figure M.4.1 presents a status report on state initiatives to decouple sales from revenues. As shown, there are 10 states with energy-efficiency programs where decoupling is not used, 11 states with energy-efficiency programs where decoupling was proposed but not adopted, three states plus the District of Columbia with energy efficiency programs where decoupling is being investigated, nine states with energy efficiency programs where decoupling has been approved for at least one utility, and one state with no energy efficiency program where at least one utility has been approved for decoupling.

[37] Mukherjee 2008.

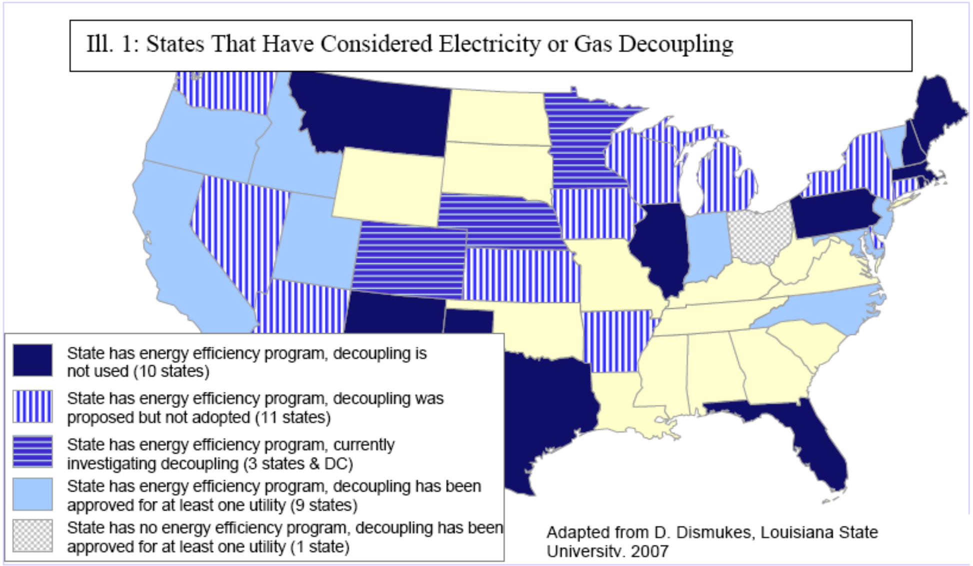

Figure M.4.1. Status of State Efforts to Decouple Electricity or Gas Sales from Revenue

Figure M.4.2 identifies states with current cost-recovery mechanisms and those with AMI cost recovery pending.[38] Based on the survey of state practices conducted by Duke Energy and KEMA, cost recovery for smart grid/AMI investments is permitted in California, Idaho, Colorado, Texas, Michigan, Georgia, and Maryland. Cost recovery is pending in Oregon, New Mexico, Iowa, Missouri, Kentucky, New York, Delaware, Connecticut, and Washington, D.C. Further, the figure identifies the cost-recovery method currently used or proposed. The three methods of cost recovery highlighted in Figure M.4.2 are purchased-power cost-adjustment tracking factors (trackers), rate recovery, and customer surcharges. See Section 3.0 for a discussion of these cost recovery methods.

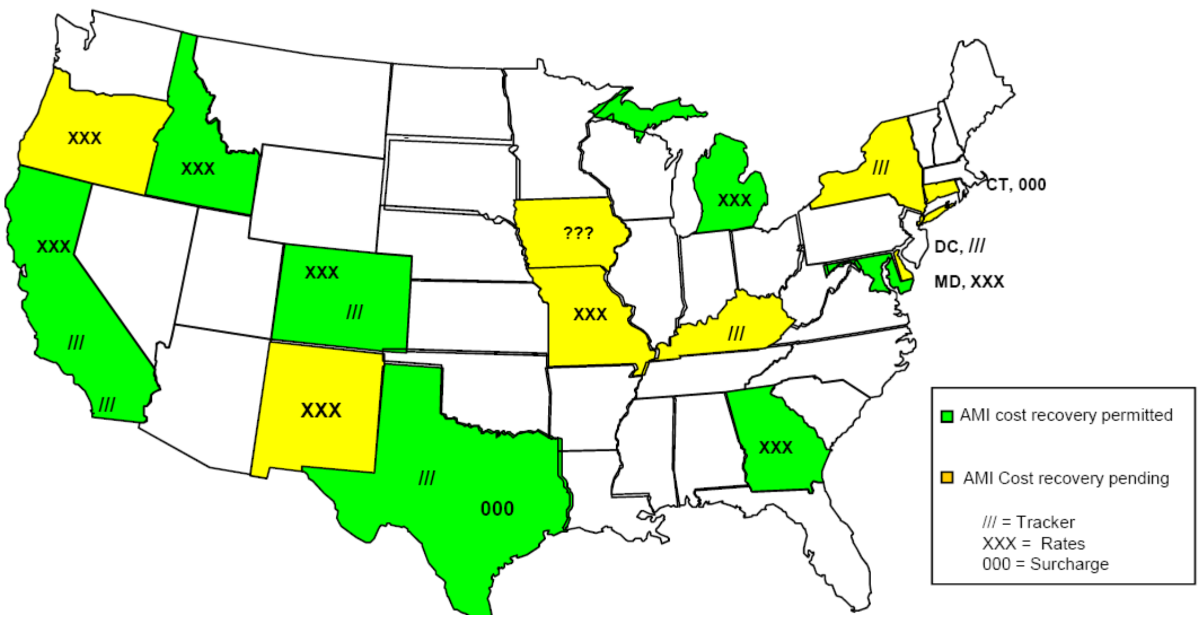

Figure M.4.2. State Cost-Recovery Methods for AMI Investments

[38]McNamara and Smith 2007.

M.4.4.0 Challenges to Deployment

There are a number of technical and business/financial barriers that are realized due to the absence of regulatory recovery of smart-grid investments as outlined below.

M.4.4.1 Technical Challenges

Technical barriers include:

- When making the case to utility commissions, technical barriers may exist due to the unproven nature of some smart-grid technologies; proof of concept may be required.
- Smart-grid related projects vary by electric-service provider in terms of functionality, requirements, and implementation approaches. General agreement is needed on the points in these systems where interfaces can be defined and stabilized. This is necessary if standards are to developed and adopted so that implementation costs and risks are reduced. (See Metric 19, Open Architecture / Standards.)

M.4.4.2 Business and Financial Challenges

Business and financial barriers include the following:

- There are significant costs to utilities when deploying new smart-grid technologies. Regulatory recovery of these costs can be an issue in some cases, and thus creates a disincentive to technology deployment.
- It may be difficult to demonstrate positive net benefits, causing consumer representatives to oppose deployment.
- Utility commissions may require more timely cost recovery than levels projected for some smart-grid investments.
- There are complications surrounding the replacement of existing undepreciated assets, such as meters.
- For utilities operating in multiple jurisdictions, the regulatory requirements in one area may not be consistent with those in another.
- Business cases should consider the societal benefits associated with smart-grid investments.[39]

M.4.5.0 Metric Recommendations

The metric analysis presented in this paper is too reliant on the sampling of service provider interviews conducted for this report (21 companies). Alternative sources of information regarding rate recovery should be identified and examined and compared with the findings of the interviews in order to validate results. Greater insight should be provided by those ultimately paying for smart-grid deployments – the end-use customer.

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[39]Miller, J. 2008. *The Smart Grid - Benefits and Challenges*. Presented at EEI Annual Convention – Toronto. Accessed November 12, 2008 at http://www.oe.energy.gov/DocumentsandMedia/SG__Benefits_Challenges_J_Miller.pdf

Metric #5: Load Participation

M.5.1.0 Introduction and Background

This metric measures the fraction of load served by interruptible tariffs, direct load control, and consumer load-control. These properties are critical for enabling measurement and modeling of a smart grid's load participation and how it responds as an actual system.

"Demand response" is defined according to the U.S. DOE in its September 2007 report to Congress:

> "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[40]

Demand response is typically viewed from a SCADA point of view as a form of additional capacity and is discussed in terms of MW. Demand response programs have seen quite a degree of variation of interest over the years. The U.S. Energy Information Administration reports that Demand Side Management (DSM) spending, one of the earlier forms of demand response peaked at $2.74 billion in 1994 before declining to $1.3 billion in 2003 and then rising again to $2.05 billion in 2006 (nominal dollars).[41]

Figure M.5.1 graphs historic and projected levels of electricity sales by sectors. Notice that, historically, residential and commercial energy sales have been below or close to industrial levels, but projections for these sectors show a marked departure from this trend with commercial sales eclipsing residential energy sales in approximately 2012.[42]

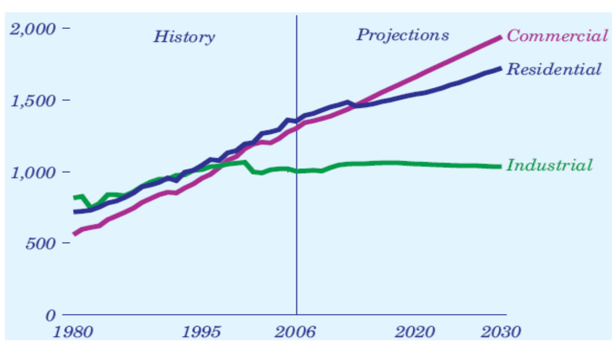

Figure M.5.1. Annual Electricity Sales by Sector, 1980-2030 (billion kWh)[43]

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[40] Federal Energy Regulatory Commission. 2007. *Assessment of Demand Response and Advanced Metering 2007.* Staff Report. Washington, D.C. Accessed November 6, 2008 at: http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf

[41] U.S. Department of Energy/Energy Information Administration (DOE/EIA). 2007. *Electric Power Annual with Data for 2006*. DOE/EIA, U.S. Department of Energy, Washington, D.C. Accessed at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html

[42] U.S. Department of Energy/Energy Information Administration (DOE/EIA). 2008. *Annual Energy Outlook 2008.* DOE/EIA-0383(2008). DOE/EIA, Washington, D.C. Accessed November 11, 2008 at: http://www.eia.doe.gov/oiaf/aeo/

[43] DOE/EIA. *Annual Energy Outlook 2008*. Page 67.

According to a 2008 FERC Survey,[44] only about 8% of customers have a time-based rate or are involved in some form of a demand response program. Similarly, the number of entities offering such programs is low, with direct load control (DLC) and interruptible/curtailable tariffs listed as the most common incentive-based demand response programs. The FERC survey has a population of 3,407 organizations of which 2,094 responded (Table M.5.1).

Table M.5.1. Entities Offering Load-Management and Demand-Response Programs[45]

Type of Program	Number of Entities
Direct Load Control	209
Interruptible/Curtailable	248
Emergency Demand-Response Program	136
Capacity-Market Program	81
Demand Bidding/Buyback	57
Ancillary Services	80

In a recent Notice of Proposed Rulemaking issued by FERC[46] regarding wholesale competition, four new incentive-based demand-response proposals were issued:

1. Allow demand-response resources to provide services such as supplemental reserves and to correct generator imbalances in RTO/ISO markets when they meet the technical requirements.
2. During emergencies, eliminate excess charges when using less energy than purchased in the day-ahead market.
3. Allow an organization that aggregates demand response to bid into organized markets on behalf of their retail customers.
4. Provisions that allow market power rules to be modified when demand is approaching available supply.

M.5.2.0 Description of Metric and Measurable Elements

The following metric identifies the most important factor in understanding and quantifying managed load:

> *(Metric 5) Fraction of load served by interruptible tariffs, direct load control, and consumer load control with incentives* – The load reduction as a percentage of net summer capacity.

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[44]Federal Energy Regulatory Commission (FERC). December 2008. *Assessment of Demand Response and Advanced Metering.* Staff report. Washington, D.C. Available at http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf.
[45]FERC 2008.
[46]FERC—Federal Energy Regulatory Commission. February 2008. "*Wholesale Competition in Regions with Organized Electric Markets. Notice of Proposed Rulemaking*." Docket Nos. RM07-19-000 and AD07-7-000. Accessed November 24, 2008 at http://www.ferc.gov/whats-new/comm-meet/2008/022108/E-1.pdf .

M.5.3.0 Deployment Trends and Projections

Currently, load participation does exist and many organizations such as the ERCOT, Public Utility Commission of Texas (PUCT), and the California and New York ISOs act to balance and curtail loads to avoid and manage brownouts and blackouts. Nationally, however, demand-response participation is very low, as indicated in Figure M.5.2 and Figure M.5.3. Figure M.5.4 shows aggregate demand response by type and region, and further demonstrates the low historic level of demand response across the United States. [47]

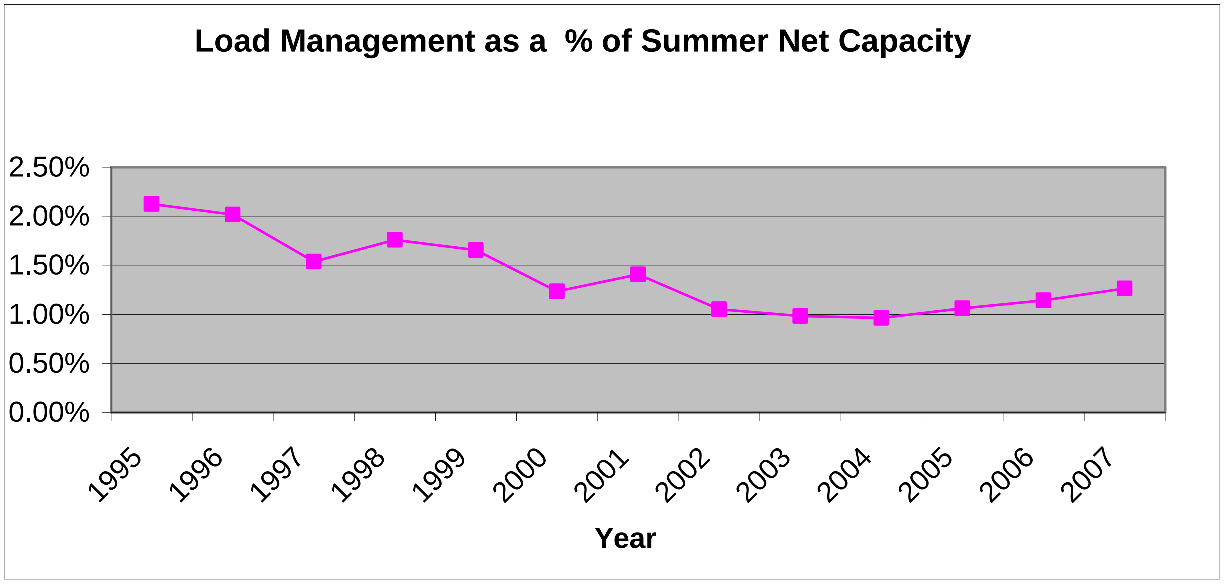

Figure M.5.2. Historic Load-Management Peak Reduction as a Percentage of Net Summer Capacity[48]

Figure M.5.3 shows the participation rate in terms of megawatts (MW). From these graphs it is clear that load management has not played a strong role in energy markets. Nationally, as a percent of net summer capacity, load managed has declined from 2% to 1%. In megawatts, the load managed declined from 16,347 to 12,566 MW, although the trend appears to moving upward since 2003. FERC reported in their 2008 Survey that approximately 8,032 MW of interruptible load plus 11,045 MW of direct load control was available. Thus, approximately 2% of net summer capacity is under direct load control or interruptible tariffs.

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[47] FERC 2007.

[48] Source: U.S. Department of Energy/Energy Information Administration (DOE/EIA). 2007. *Electric Power Annual 2006.* DOE/EIA, Washington, D.C. (Data from Tables 2.1 and 9). Accessed November 6, 2008 at http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile2_1.xls and http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile9_1.xls

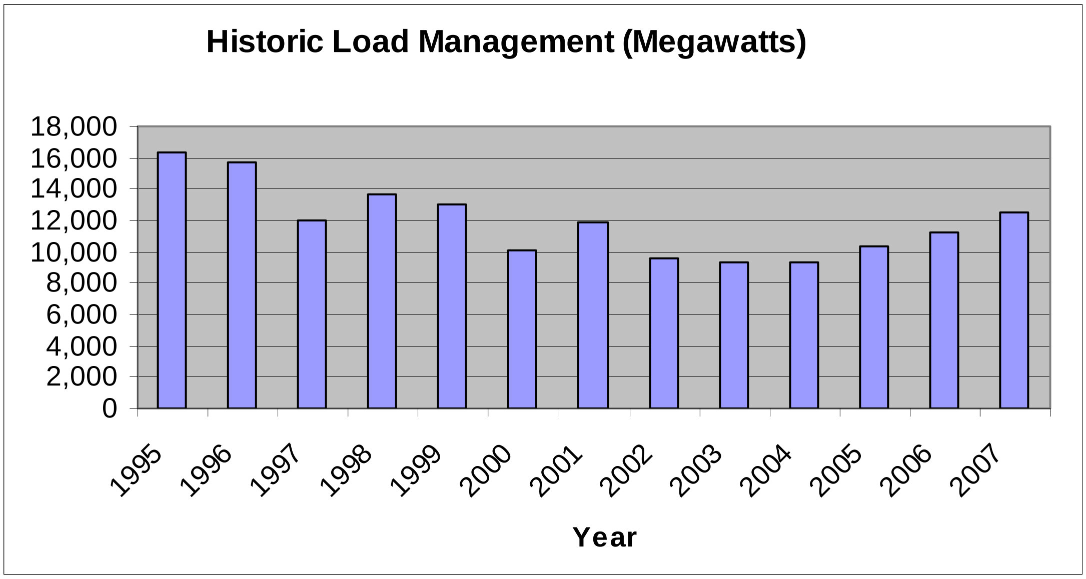

Figure M.5.3. National Historic Demand-Response and Load-Management Peak Reduction in MWs[49]

Despite the measures discussed in Section 1, EPRI expects the impact of demand-response programs to be low at least until 2030; with DER responsible for a reduction of less than 0.1% from the base load in the base case for 2030, and with 5% as an "aggressive" target.[50]

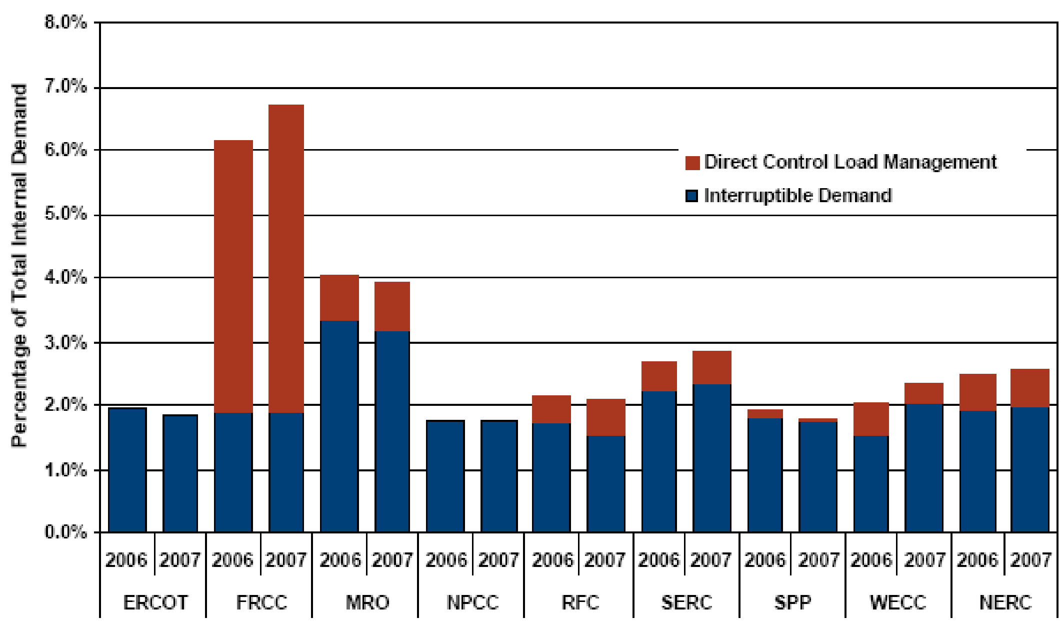

Figure M.5.4. Demand Response by NERC Region[51]

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[49]Source: Energy Information Administration. Data from table 9, EIA 2008. Available at http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile9_1.xls

[50]Amarnath, Ammi. 2008. *Heat Pump Water Heaters: Demonstration Project*. Presentation at the ACEE Forum on Water Heating and Use. Electric Power Research Institute (EPRI). Accessed November 6, 2008 at http://www.aceee.org/conf/08whforum/presentations/4a_amarnath.pdf.

This metric measures the fraction of load served by interruptible tariffs, direct load control, and consumer load control with incentives. Interviews conducted for this report (see Annex B) indicated little development of load control and customer participation in demand-response programs. Those replying to the question “Do you have remote load control of customer high energy devices?” indicated as follows:

- 24 % -- none
- 14 % -- in development
- 48% -- less than 10% of all customers
- 14% -- between 10% and 70% of all customers
- 0% -- greater than 70% of all customers

Companies responding to the question “Do you have customer participation in demand/response?” indicated that they had:

- 14 % -- none
- 10 % -- planned
- 62% -- less than 10% of all customers
- 14% -- between 10% and 70% of all customers
- 0% -- greater than 70% of all customers

M.5.3.1 Associated Stakeholders

Stakeholders include the following:

- End users (consumers): residential, commercial, industrial. With the advent of more incentives by distribution and transmission providers, load managed could rise significantly and end users will have more supply options and incentives to improve energy efficiency.
- Electric-service retailers: regulated and unregulated electricity providers, provide energy services based on market incentives and supply.
- Local, state, and federal energy policy makers: will need to evaluate the effects of current regulations in demand response.
- Transmission providers: provide response programs for transmission of electricity.
- Distribution providers: will provide incentive programs to encourage demand response.
- Generation and demand wholesale-electricity traders/brokers: managing the generation required to meet load.
- Product and service providers: in providing the communication technologies that will provide supply and demand information to both providers, transmitters and end-users.

M.5.3.2 Regional Influences

Regional influences should not create many obstacles for this metric. However there are a few regional considerations that may create difficulties in analysis when aggregating regional data to the state and national level. For example, differences in the frequency of load and demand measurements (seconds, minutes, hours, days) may introduce interpolation or extrapolation errors. This could be

[51] FERC 2007. Page C-1.

especially true for regions that find it difficult or expensive to monitor and/or communicate such data, such as sparsely-populated rural areas with poor wireless-communication coverage. Further, regional differences in load participation levels will vary both in terms of time of day and volume. For example regions in Pacific Standard Time will experience their typical on-peak hours one hour later than regions in the Mountain Standard Time zone, and the volume of the participating load may vary significantly from one region to another. Direct load control is much higher in the Florida Reliability Coordinating Council (FRCC) than in other areas (see Figure M.5.4). Interruptible demand is much higher (3.0% of internal demand) in the Midwest Reliability Organization than in other regions (less than 2.0% of internal demand).

M.5.4.0 Challenges to Deployment

The technical, business and financial, and policy challenges to demand participation follow.

M.5.4.1 Technical Challenges

Literature reviews identified a "lack of third-party access" to usage data as well as "insufficient market transparency"[52] as key barriers to developing functional demand response programs.

Timely access to meter data and communication infrastructure, probably from advanced-metering systems, is vital to supplying the energy market with the data necessary to track energy prices, estimate and execute demand response measures, and provide consumers and suppliers accurate, real-time data. A deployment that does not consider ways of increasing data availability and market transparency risks failing to provide sufficient price information to consumers, demand information to producers, and market information to innovators.[53]

Additional technical considerations include standardization of metering, and/or appliance timers and communication equipment, i.e., "plug and play," and how data will be communicated from household meter to utility company. Demand-response programs need to address the lack of utility signals that reflect utility needs. Further technical issues could include incorporation of local and regional objectives that could be addressed only through customization of demand-response programs. Another technical issue could be the use of installed equipment for persistent control rather than for emergency curtailment. Demand-response programs will also need to be able to regulate loads up or down to accommodate intermittent renewable resources.[54]

M.5.4.2 Business and Financial Challenges

The expense of increasing load participation comes from both the supply side and the demand side of the market. Companies may need to invest in new load-management programs and/or refine current SCADA techniques. Further costs of developing and installing hundreds of thousands to millions of units

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[52]Federal Energy Regulatory Commission. 2006. *Assessment of Demand Response and Advanced Metering.* Staff Report. Docket Number: AD-06-2-000. Washington, D.C. August 2006. Accessed November 25, 2008 at http://www.ferc.gov/legal/staff-reports/demand-response.pdf

[53]FERC 2006.

[54] Callahan SJ. 2007. "Smarter Meters Require Open Standards". *Electric Light and Power*. Accessed November 6, 2008 at http://uaelp.pennnet.com/display_article/284514/34/ARTCL/none/none/Smarter-Meters-Require-Open-Standards/

of load-management and demand-response equipment, be that some form of advanced metering or otherwise, represent large investments of capital that must be raised or recovered and may pose a significant challenge to utility companies.[55]

On the demand side, customers need to be educated about the potential savings (earnings) from their participation. Additionally, they will need simple, user-friendly enabling technologies that inform them of grid events (electricity prices, shortages, etc.) and allow them to operate their electrical loads in accordance with these events.

M.5.5.0 Metric Recommendations

More information concerning the resource make-up of load participation is desired. Coordination with EIA to obtain greater information about the content of the load management variable should be considered. Form 861 doesn't provide a clear definition of what is measured. Furthermore information on the applicability or response to the total population from FERC in its Demand Response survey could provide further insights in the amount of load that is actually being captured.

[55] Steklac, I. "AMI: Bridging the Gaps." *Next Generation Power & Energy*. Accessed November 6, 2008 at http://www.nextgenpe.com/currentissue/article.asp?art=271002&issue=215

Metric #6: Load Served by MicroGrids

M.6.1.0 Introduction and Background

Microgrids may change the landscape of electricity production and transmission in the United States due to the changing technological, regulatory, economic, and environmental incentives. The changing incentives could allow the "modern grid" to evolve into a system where centralized generating facilities are supplemented with smaller, more distributed production using smaller generating systems, such as small-scale combined heat and power (CHP); small-scale renewable energy sources (RES) and other distributed energy resources (DERs). The development of new technologies in power electronics, control, and communications,[56] along with the combined values of heat and electricity through cogeneration, added reliability, security, and stability may offset the lower costs of centralized generation.[57]

A microgrid is an integrated distribution system with interconnected loads and distributed energy sources and storage devices, which could be as small as a city block or as large as a small city, and which operates connected to the main power grid, but is capable of operating as an island.[58,59] Key distinctions between a microgrid and distributed generation are its ability to be islanded with coordinated control, and that it contains more than one generating source.

In "Grid 2030," the Department of Energy sees microgrids as one of three cornerstones of the future grid.[60] Microgrids are seen as local power resources that are connected to the regional grid to provide distributed energy resources while managing local energy supply and demand.[61]

Microgrids will add three features to the electric system: efficiency (by combining heat and power); matching of security, quality, reliability, and availability with the end-users needs; appearing to the electric system as a controlled entity.[62] Microgrids using combined heat and power (CHP) can capture as much as 85 percent of the energy used in generating electricity by also powering heating and cooling

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[56]Lasseter R, A Akhil, C Marnay, J Stephens, JE Dagle, RT Guttromson, AS Meliopoulos, R Yinger and J Eto. 2002. *Integration of Distributed Energy Resources: The CERTS MicroGrid Concept* LBNL-50829. Lawrence Berkeley National Laboratory, Berkeley, California. Accessed November 13, 2008 at http://www.osti.gov/bridge/servlets/purl/799644-dfXsZi/native/799644.PDF

[57]Agrawal, P, M Rawson, S Blazewicz, and F Small. 2006. "How 'Microgrids' are Poised To Alter The Power Delivery Landscape." *Utility Automation & Engineering T&D,* August, 2006, Accessed November 4, 2008 at http://uaelp.pennnet.com/Articles/Article_Display.cfm?Section=ARTCL&ARTICLE_ID=260536&VERSION_NUM=2&p=22&pc=ENL

[58]Lasseter et al. 2002.

[59]Rahman, S. 2008. *A Framework for a Resilient and Environment-Friendly Microgrid With Demand-Side Participation.* Advanced Research Institute, Virginia Polytechnic Institute and State University, Arlington, Virginia. Accessed November 4, 2008 at http://www.ieee.org/organizations/pes/meetings/gm2008/slides/pesgm2008p-000334.pdf.

[60]DOE—U.S. Department of Energy. July 2003. "*Grid 2030: A National Vision for Electricity's Second 100 Years". Office of Electric Transmission and Distribution*. Accessed November 4, 2008 at http://www.oe.energy.gov/DocumentsandMedia/Electric_Vision_Document.pdf.

[61]Ye, Z, R Walling, N Miller, P Du, and K Nelson. 2005. *Facility Microgrids*. National Renewable Energy Laboratory, NREL/SR-560-38019. Accessed November 4, 2008 at http://www.nrel.gov/docs/fy05osti/38019.pdf.

[62]Marnay C, and R Firestone. 2007. "*Microgrids: An Emerging Paradigm for Meeting Building Electricity and Heat Requirements Efficiently and with Appropriate Energy Quality*. Lawrence Berkeley National Laboratory, LBNL-62572. Presented at the European Council for an Energy Efficient Economy 2007 Summer Study, La Colle sur Loup, France. Accessed November 4, 2008 at http://eetd.lbl.gov/EA/EMP/reports/62572.pdf.

systems. In comparison, central grid generation may lose up to 60 percent of the energy because of losses in transmission and venting heat into the atmosphere. In addition, microgrids can supplement power to the electric system by injecting power into the central grid during peak periods.[63] Microgrids can also achieve 99.999% reliability compared with 99.9% reliability for the centralized grid.[64]

A three-phase implementation path was recommended to the Department of Energy for the development of microgrids in 2005. During the first phase, pilot cases will examine the ability of microgrids to reduce costs of power and develop technologies to automatically connect/disconnect the microgrid from the central grid. Phase II pilot cases are expected to examine the security and resiliency of microgrids with higher penetration rates, and Phase III will examine a microgrid's ability to export power to central grid. Each phase will also address regulatory challenges. Phase I will seek to enhance retail competition while providing fair compensation to utilities for investment and services provided. Phase II will focus on cost recovery of security investments, while Phase III will emphasize transparency of costs to end-users, including real-time and environmental benefits.[65,66] The CERTS microgrid, a joint demonstration project funded by DOE and the California Energy Commission (CEC) is used to provide research and development experience on technical, business and regulatory issues associated with microgrids.[67]

There are few commercial examples currently operating as the commercial microgrid is in its infancy. Rahman[68] provides two microgrid examples. He describes a Wal-Mart store that has six 60 kW microturbines that provide cooling, heat and electricity. The system has an overall efficiency of 80 percent. In the second example, 4 Times Square in New York City has two 200 kW fuel cells, 15 kW of integrated PV panels and natural-gas powered absorption chillers/heaters that provide heat, cooling and electricity. Another example is the Mad River Park Microgrid (MRPM).[69] The MRPM connects five commercial and industrial facilities and up to 12 residences to multiple generation and storage devices. Yeager[70] discusses the microgrid installed at the Illinois Institute of Technology but gives no capacity values. There are many examples of microgrids at university, petrochemical, and Department of Defense (DoD) sites.[71]

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[63]PSPN—Penn State Policy Notes. 2008. *Reducing Demand, Promoting Efficiency Key to Defusing Electric Rate Increases.* Center for Public Policy Research in Environment, Energy and Community Well-Being. Accessed November 4, 2008 at http://www.ssri.psu.edu/policy/GeneralPolicyBrief_0415.pdf

[64]NC—Navigant Consulting, October 2005. *Microgrids Research Assessment Phase 2*. Accessed November 4, 2008 at http://der.lbl.gov/2006microgrids_files/Navigant%20Microgrids%20Final%20Report.pdf

[65]Agrawal et al 2006.

[66]Navigant Consulting 2005.

[67]DOE—U.S. Department of Energy. ca. 2006. "*Advanced Distribution Technologies & Operating Concepts: Microgrids." Office of Electricity Delivery and Energy Reliability*. Accessed November 4, 2008 at http://www.electricdistribution.ctc.com/microgrids.htm.

[68]Rahman 2008.

[69]RDC—Resource Dynamics Corporation. 2005. *Characterization of Microgrids in the United States: Final Whitepaper*. Accessed November 4, 2008 at http://www.electricdistribution.ctc.com/pdfs/RDC_Microgrid_Whitepaper_1-7-05.pdf.

[70]Yeager KE. 2007. "Facilitating the Transition to a Smart Electric Grid." Testimony before the House Energy and Commerce Committee. Accessed November 4, 2008, at http://energycommerce.house.gov/cmte_mtgs/110-eaq-hrg.050307.Yeager-Testimony.pdf

[71]RDC 2005.

M.6.2.0 Description of the Metric and Measurable Elements

The following three measures have been identified as important for understanding the number of microgrids and the amount of capacity they serve.

(Metric 6.a) the number of microgrids in operation. Microgrids must meet the definition in Section 1 above.

(Metric 6.b) the capacity of microgrids in MW.

(Metric 6.c) the percentage total grid summer capacity. This metric measures the impact these microgrids are having on the ability of microgrids to meet electricity-supply requirements of the entire grid.

M.6.3.0 Deployment Trends and Projections

Currently, approximately 20 microgrids can be found at universities, petrochemical facilities and U.S. defense facilities. According to RDC[72] the microgrids provided 785 MW of capacity in 2005. They noted additional microgrids that were in planning at the time as well as demonstration microgrids. RDC also noted that by examining the Energy Information Administration's database they could determine approximately 375 potential sites for microgrids if they weren't already microgrids. Outside of the petrochemical microgrids, there are no commercial microgrids in the United States.[73] Given EIA's net summer capacity of 906,155 MW and assuming no devolution of microgrid capacity from 2005, the percentage of capacity met by microgrids is about 0.09% in 2006.

Table M.6.1. Capacity of Microgrids in 2005 (MW)[74]

	University	Petrochemical	DoD
Capacity (MW)	322	455	8

Current projections and forecasts for microgrids are as follows:

- Navigant Consulting, in their base case scenario, projected 550 microgrids installed and producing approximately 5.5 GW by 2020[75] or about 0.5% of projected capacity.[76] Navigant[77] predicts a range of 1-13 GW depending on assumptions about pushes for more central power, requirements and demand for reliability from customers and whether there is an environmental requirement for carbon management.

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[72] RDC 2005.
[73] PSPN—Penn State Policy Notes. 2008. "Reducing Demand, Promoting Efficiency Key to Defusing Electric Rate Increases." Center for Public Policy Research in Environment, Energy and Community Well-Being. Accessed November 4, 2008 at http://www.ssri.psu.edu/policy/GeneralPolicyBrief_0415.pdf
[74] RDC 2005.
[75] Navigant Consulting 2005.
[76] DOE—U.S. Department of Energy. June 2008. *Annual Energy Outlook 2008 with Projections to 2030***.** Energy Information Administration, DOE/EIA-0383(2008). Accessed November 4, 2008 at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html
[77] Navigant Consulting 2005.

M.6.3.1 Associated Stakeholders

There are numerous stakeholders associated with microgrids, but the primary stakeholders (in no particular order) include:

- End users, including distributed-generation owners and customers, who need reliable, high quality power. Offsetting costs by selling excess power and/or heat has the potential to make programs more economical and attractive.
- Distribution-service providers who, depending on their size, location, and ability to integrate microgrid power production, as well as utilities and municipalities, could significantly benefit from integration of microgrid resources into their overall resource portfolio.
- Electric-service retailers
- Products and services suppliers of generation, control, and communications equipment that enable microgrid operation
- Policymakers
- Policy advocates, particularly environmental-policy advocates.

M.6.3.2 Regional Influences

Regional influences should not create many obstacles for this microgrid development. Potential regional influences are driven more by how stakeholders in different regions of the country will interface or integrate with one another, and how regional or state regulators in the utility and environmental areas will either support or hinder distributed-energy resource development. (See Metric 3 for differences in acceptance of interconnection standards.)

Microgrids can be favorable in remote places such as in Alaska and Hawaii, where significant periods of islanded operation can be expected. Microgrids with CHP may be of greater value in colder climates (northern states) or regions where heating and cooling requirements are significant.

M.6.4.0 Challenges to Deployment

Unfortunately, several barriers have been identified that may stifle the deployment of microgrid systems in the United States. As in other industries, regulatory barriers and their economic impacts are more significant challenges to deployment than the technical challenges. While there are several regulatory barriers, the business and financial challenges listed below are those with highest impact.

M.6.4.1 Technical Challenges

While the business and financial challenges are more significant, there are technical challenges to moving microgrid deployments forward. The primary challenges include:

- Interconnection—interconnection requirements must be resolved through standards such as IEEE 1547.4; otherwise seamless transitions will not occur.[78] Completion of the IEEE 1547.4 standard for

[78] Navigant Consulting 2005.

microgrid requirements is also needed.[79]

- Large-scale microgrids— as the interconnection points increase, large microgrids with multiple points of integration become more complicated to coordinate and protect.[80]
- Penetration level—the level of penetration could become an issue if the load served by microgrids becomes large enough that they are serving more than their own demand, and system events such as lightning strikes or other system failures cause the microgrid to respond by disconnecting from the regional grid leaving other dependent entities without power.[81]
- Security—some concern exists regarding the level of security, both physical and cyber, required for microgrids to be a reliable resource.[82]
- Power generation types—for alternative-energy resources such as renewable energy, fuel cells and microturbines, the lack of experience with system design and integration will provide technical challenges.[83,84]
- Power quality—power quality may be impacted by current IEEE 1547 standards, as microgrids may be forced off the grid when stability events occur. Power quality in the microgrid is a function of its size, impedance, and load level.[85]
- Intentional islanding—the transition between regional grid-parallel and isolated operation can leave microgrids without power for periods from seconds up to minutes. The impact on loads within the microgrid due to transient effects or disruption isn't acceptable. A more instantaneous transition is required.[86]

M.6.4.2 Business and Financial Challenges

The most significant business and financial challenge is making the business case for microgrids. A part of the business case includes ensuring that microgrids are not made infeasible by standby charges, interconnection policies that discourage or prohibit microgrids, and the loss of revenues faced by utilities as microgrids are deployed. But, the business case must also be effectively shown for the value of combined heat and electricity generation, added security, reliability, and power quality in order for investment to take place.[87] Significant challenges to the business case include:

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[79] IEEE. 2008. *1547 Series of Standards*. Institute of Electrical and Electronic Engineers. Accessed November 4, 2008 at http://grouper.ieee.org/groups/scc21/dr_shared/. (Last updated 12/21/2007).
[80] Ye, Z, R Walling, N Miller, P Du, and K Nelson. 2005. *Facility Microgrids*. National Renewable Energy Laboratory, NREL/SR-560-38019. Accessed November 4, 2008 at http://www.nrel.gov/docs/fy05osti/38019.pdf.
[81] Ye 2005.
[82] NETL—National Energy Technology Laboratory. 2007. "Barriers to Achieving the Modern Grid". Department of Energy, Office of Electricity Delivery and Energy Reliability. Accessed November 4, 2008 at http://www.netl.doe.gov/moderngrid/docs/Barriers%20to%20Achieving%20the%20Modern%20Grid_Final_v1_0.pdf
[83] Ye 2005.
[84] Navigant Consulting 2005.
[85] Navgant Consulting 2005.
[86] Ye 2005.
[87] Navigant Consulting 2005.

- Standby charges—charges assessed to end-users on their installed capacity if it isn't used solely for emergency purposes. Utilities use the standby charge to pay for the infrastructure necessary to serve the microgrid's load in the event the microgrid's generating capability becomes unavailable. These charges for rarely-used infrastructure are a significant economic barrier to microgrid deployments.[88,89]
- Interconnection—the policies and procedures that describe how power-generating capacity not owned by the utility will be connected and integrated into the power grid. Without national or regional policies and procedures, utilities can develop their own policies and procedures that discourage interconnection of power-generating capacity that they do not own or control.[90] (See Metric 3)
- Lost utility revenues—The way the U.S. utilities are regulated, they exhibit strong economies of scale that make competition from smaller, less-efficient suppliers significantly less economical. In addition, utilities have no financial motivation to look at grid innovations that reduce their sales. Utilities have commonly raised barriers to interconnection and self-generation and also discourage energy-efficiency investments because of the significant likelihood of a loss of revenue and profits.[91]

M.6.5.0 Metric Recommendations

The number and capacity (MW) of microgrids needs to be added as a sub-category of distributed generation where DG can be islanded and controlled to allow for the enumeration and quantification of microgrids.

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[88]Hatziargyriou N. 2008. *"Microgrids: the Key to Unlock Distributed Energy Resources?"* Accessed November 4, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=04505823.
[89]Venkataramanan G and C Marney. 2008. "A Larger Role for Microgrids," *IEEE Power and Energy Magazine*, pp.78-82. Accessed November 4, 2008 at http://eetd.lbl.gov/EA/EMP/reports/microgrids-larger-role.pdf
[90]Venkataramanan and Marney 2008.
[91]Venkataramanan and Marney 2008.

Metric #7: Grid-Connected Distributed Generation and Storage

M.7.1.0 Introduction and Background

This metric measures the quantities and types of distributed-generation and energy-storage equipment that are connected to the grid. Distributed-generation systems are atypical compared to the large and centralized generators that provide most of the grid's power. Rather, DG systems are noted for their smaller-scale local power-generation (10 MVA or less) and distribution systems, and generally have low installation and maintenance costs.

This category includes power generators such as wind turbines connected at the distribution system level, micro hydro installations, solar panels, diesel, etc. These distributed generators produce power for onsite or adjacent consumption and sometimes sell surplus capacity back into the grid under an established feed-in tariff. This metric also covers energy-storage devices such as batteries and flywheels which could be used to store energy produced or purchased during off-peak hours and then sold or consumed during on-peak hours.

M.7.2.0 Description of Metric and Measurable Elements

Electricity sold or stored from DG will be classified into one of 6 categories: internal combustion, combustion turbine, steam turbine, hydroelectric, wind, and other. After recording the classification and the quantity (kW, MW…) of power, the following dimensions will be established. These metrics should not include DG and storage which is not grid-responsive or is available for emergency capacity only. Measures could separate out important new technologies as they help even-out required dispatchable generation. This would include storage that enables time-varying voltage regulation. At this time there are few storage options.

The following three metrics have been identified as important aspects to understanding and quantifying grid-connected distributed generation and storage.

(Metric7.a) Percentage of actively-managed fossil-fired, hydrogen, and biofuels distributed generation. This metric excludes DG whose operation does not respond to grid conditions and excludes emergency, backup generation capacity that is only operated when there is an outage. Must be connected to the distribution system or distribution substation to qualify. Both installed MW and supplied MWh are measured as a percentage of total DG and total grid generation capacity/supply.

(Metric7.b) Percentage of actively-managed batteries and flywheels, excluding transportation applications. Both MW and MWh would be measured as a percentage of total DG and total grid generation capacity/supply.

(Metric7.c) Percentage of non-dispatchable renewable generation. This includes such generation connected anywhere in the grid, though a distinction should be made between distribution- and transmission-connected generation. Both MW and MWh would be measured as a percentage of total DG and total grid generation capacity/supply.

M.7.3.0 Deployment Trends and Projections

Distributed generation capacity has been a small part of total power generation, with combined total distributed generation capacity ranging from 5,423 MW in 2004, to 12,702 MW in 2007.[92] See Figure M.7.1. Available U.S. generating capacity in 2007 comprised 915,292 MW, while summer peak demand reached 782,227 MW and winter peak demand was 637,905.[93] Thus, while grid-connected generation capacity increased 134 percent over three years it still only represented 1.4% of grid capacity, 1.6% of summer peak and 2.0% of winter peak demand.

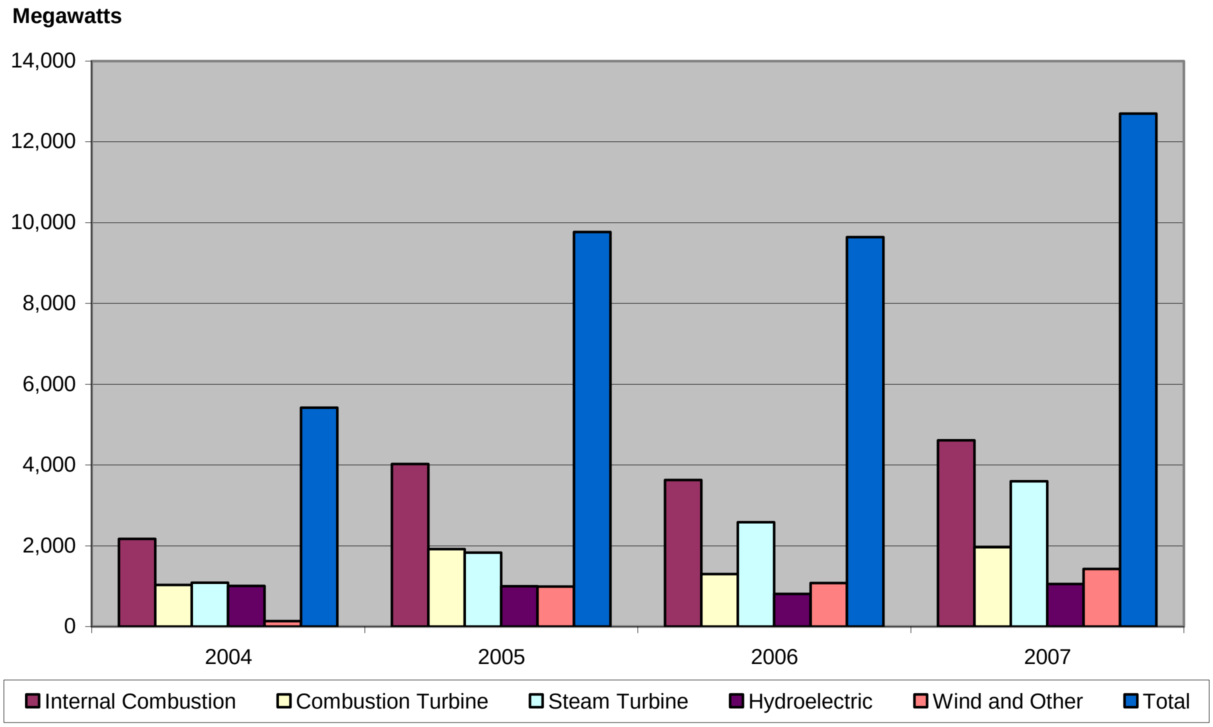

Figure M.7.1. Yearly installed DG capacity by technology type[94]

Actively-managed fossil-fired, hydrogen, and biofuels distributed generation capacity reached 10,173 MW in 2007, up 112% from 2004. This represented approximately 1.1% of total generating capacity and 80% of total DG. Wind and other renewable energy sources grew significantly between 2004 and 2007, increasing by 941%, yet they only represent 0.16% of total available generating capacity, 0.18% of summer peak capacity, and 0.22% of winter peak.[95] Intermittent renewable-energy resources such as wind may not be effective countermeasures for peak demand reduction, although solar has the potential to be more coincident with summer peak-demand periods.

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[92] Energy Information Administration (EIA). 2009. *Capacity of Distributed Generators by Technology Type, 2004 through 2007*. Accessed January 30, 2009 at http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile2_7b.pdf
[93] EIA 2009.
[94] EIA 2009.
[95] EIA 2009.

Interviews conducted in support of this report (see Annex B) indicated the following about grid-connected DG:

- Grid connected DG was reported by only 0.69% of service provider customers.
- Storage capacity was indicated by 3 entities comprising about 0.3 percent of their total customers
- Non-dispatchable renewable generation was reported by only 1.4% of total customers.

Table M.7.1. Yearly Installed DG Capacity by Technology Type[96]

Capacity of Distributed Generators by Technology Type, 2005 and 2006
(Count, Megawatts)

	Internal Combustion	Combustion Turbine	Steam Turbine	Hydroelectric	Wind and Other	Total	
Period	**Capacity**	**Capacity**	**Capacity**	**Capacity**	**Capacity**	**Number of Units**	**Capacity**
2004	2,169	1,028	1,086	1,003	137	5,863	5,423
2005**	4,024	1,917	1,831	998	994	17,371	9,766
2006	3,625	1,299	2,580	806	1,078	5,044	9,641
2007	4,614	1,964	3,595	1,053	1,427	7,103	12,702

** Distributed generator data for 2005 includes a significant number of generators reported by one respondent that may be for residential applications.
Note: Distributed generators are commercial and industrial generators that are connected to the grid. They may be installed at or near a customer`s site, or elsewhere. They may be owned by either the customers of the distribution utility or by the utility. Other Technology includes generators for which technology is not specified.

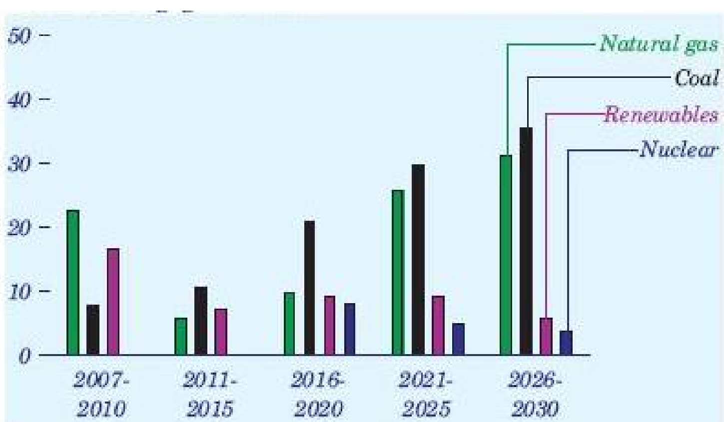

Figure M.7 2. Electricity Generation Capacity Additions by Fuel Type, 2007-2030 (gigawatts)[97]

While DG systems have large startup costs for customers, some technologies, such as solar panels, can be easily installed on rooftops by homeowners and safely generate power for years. Solar power

[96]DOE/EIA. 2009. Form EIA-861, *Electric Power Annual*. Table 2.7.B. Accessed January 30, 2009 at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html
[97]DOE/EIA 2007. *Energy Market Impacts of a Clean Energy Portfolio Standard – Follow-up.*

installed in this way has a cost of $10 to $12 per watt,[98] although in the future these costs could become much lower.[99] These costs and the costs for other DG technology are expected to fall by 10% for the first three capacity doublings, then fall to 5% for the next 5 doublings. After this point, projected costs fall by 2.5% for all following capacity doublings.[100] Given cost decreases and advancements in other technologies, it is projected that DG generational capacity will reach 5.1 GW by 2010 and 7.5 GW over the next 5 years (see Figure M.7.3).[101] Note, that DG capacity discrepancy between these numbers and those reported early is mainly due to the fact that only grid-connected DG is reported in Table M.7.1.

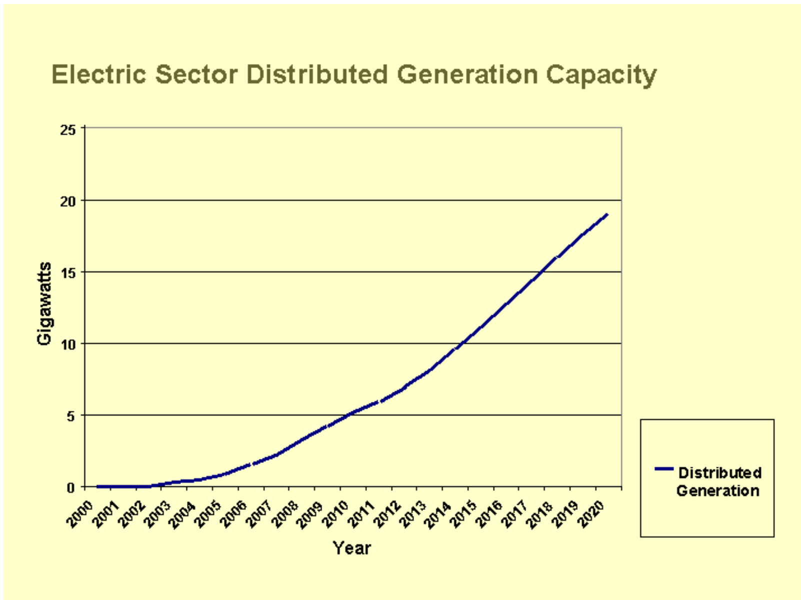

Figure M.7.3. Projected DG Capacity in GW[102]

M.7.3.1 Associated Stakeholders

Associated stakeholders include:

- End-users (customers). Distributed-generation technology allows customers to act as both buyers and sellers in the energy market. Customers can save money by substituting their own generational capacity for expensive on-peak electricity or temporarily reduce their household consumption and sell their electricity back into the market at high peak prices.[103] Further, DG technology allows customers

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[98]The Solar Guide. *Solar Cost FAQ*. Moxy Media, Guelph, Ontario. Accessed November 7, 2008 at http://www.thesolarguide.com/solar-power-uses/cost-faq.aspx .
[99]*Next Energy News*. December 19, 2007. "Nano Solar Begins Production of $1 per watt Thin-Film Panels." Accessed November 7, 2008 at http://www.nextenergynews.com/news1/next-energy-news12.19d.html
[100]Eynon RT. ca 2007. *The Role of Distributed Generation in U.S. Energy Markets*. U.S. Department of Energy, Energy Information Administration, (DOE/EIA) Washington, D.C. Accessed November 7, 2008 at http://www.eia.doe.gov/oiaf/speeches/dist_generation.html
[101]U.S. Department of Energy, Energy Information Administration. 2007. *Energy Market Impacts of a Clean Energy Portfolio Standard – Follow-up*. SR/OIAF/2007-02, DOE/EIA, Washington, D.C. Accessed November 24, 2008 at http://www.eia.doe.gov/oiaf/servicerpt/portfolio/index.html
[102]Eynon 2007.
[103] Construction WebLink. 2005. "*Distributed Generation: The Benefits Companies Can Reap y Generating Their Own Power" Accessed on August 28, 2008 at*

to contribute or draw electricity based on environmental standards that they choose. On shorter time scales, storage can assist with balancing and ramping of environmentally friendly, but intermittent, energy resources. If energy deposited into the grid is tracked by source type, consumers can choose to purchase more environmentally friendly energy sources such as wind or solar power, or supply their own "green" power into the market. Additionally, should the grid experience technical problems or an emergency occurrence, customers can disconnect from the grid and generate their own power and/or draw from battery-stored reserves.[104]

- Distribution service providers or utility companies. Utility companies, on the other hand, face a different set of risks. While DG offers the grid access to quick and cheap resources which expand grid flexibility and capacity,[105] DG will also require a significant investment of resources to manage the quality of the power being supplied, as well as the purchase of new infrastructure to dispatch DG resources;
- Distributed-generation and storage-device manufacturers: Suppliers will have a stake in developing lower-cost technologies and making those devices more cost effective;
- Balancing authorities. Balancing authorities are important stakeholders as non-dispatchable renewable generation grows as a proportion of total grid generation capacity;
- Transmission providers. Transmission providers will also have a stake as distributed generation grows to be a larger proportion of the total generation capacity and they need control for power quality issues;
- Local, state and federal energy policy makers may need to develop policies on DG cutoff standards;
- Standards organizations and their developers will need to respond to policy makers on DG cut-off standards.

M.7.3.2 Regional Influences

Different states and regions may have regulations for the quality of the power being sold or how the power is produced. Some states may value DG capacity differently from others and offer different subsidies and/or taxes based on those values. For example, Oregon state law has specific plant site-emissions standards for minor sources emitting pollutants such as NOx, SO_2, CO, particulate matter (PM), etc., whereas Ohio relies on the Best Available Technology (BAT) standard with specific limitations for PM and SO_2 based on location, generator type, and size.[106] Please see Metric 3 on DG Interconnection for more details on state interconnection differences. Additionally, in accordance with the U.S. Federal

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http://www.constructionweblinks.com/Resources/Industry_Reports__Newsletters/Sep_19_2005/dist.html. September 19th 2005

[104] Construction WebLink. 2005.

[105] Thelen LLP. September 19, 2005." Distributed Generation: The Benefits Companies Can Reap by Generating Their Own Power." *Construction WebLinks.* Accessed November 7, 2008 at http://www.constructionweblinks.com/Resources/Industry_Reports__Newsletters/Sep_19_2005/dist.html.

[106] Energy and Environmental Analysis, Inc. 2004. *Economic Incentives for Distributed Generation*. Accessed November 7, 2008 at http://www.eea-inc.com/rrdb/DGRegProject/Incentives.html

Government's Green Power Purchasing Goal, states tend to offer the most incentives for distributed generation projects that use recognized renewable energy sources.[107]

M.7.4.0 Challenges to Deployment

Distributed generation produces significant technical, business and legal challenges for the grid. The technical challenges include integrating DG resources while maintaining the level and quality of voltage and workable protection coordination. Business and financial challenges include the costs to utilities of integrating DG resources and ensuring a flexible enough system that consumers can afford to recover investments in DG resources.

M.7.4.1 Technical Challenges

Technical challenges to deployment include,

- standardization of the DG system interface with the grid (see Metric 3),
- operation and control of the distributed generation; DG may also make fault detection more difficult,[108]
- planning and design,
- voltage regulation.[109]

Of course, both the DG and storage resources being considered here share similar monitoring and control challenges identified for demand-response metrics (Metrics 3 and 5).

The system interfaces associated with incorporating DG resources widen significantly from the traditional grid interface. Internal combustion engines, combustion turbines and small hydropower generation require synchronous or induction generators to convert to the prime source and power frequency. Fuel cells, wind turbines, photovoltaics and batteries require inverters. The challenge is to bring the sources online and maintain system voltage and frequency. In addition, the inverters used to transform DC power generation units to AC power can increase harmonics in the grid.[110]

Voltage-regulation challenges are greater than just changing the transformer. The problem will include overvoltage issues which can arise due to ungrounded DG connected generation.[111] Driesen and Belmans (2006) point out that DG will present technical hurdles in terms of frequency, voltage level, reactive power and power conditioning.

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[107]Database of State Incentives for Renewables & Efficiency (DSIRE). 2008. *Federal Incentives for Renewable Energy: U.S. Federal Government - Green Power Purchasing Goal*. Accessed November 8, 2008 at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US01R&State=Federal&currentpageid=1
[108]Driesen, J and R Belmans. 2006. "Distributed Generation: Challenges and Possible Solutions. In *2006 IEEE Power Engineering Society General Meeting*. I nstitute of Electrical and Electronics Engineers, Piscataway, New Jersey.
[109]Pai MA. 2002. *Challenges in System Integration of Distributed Generation with the Grid*. Presented at Power Electronics and Fuel Cells Component System Integration Workshop, University of Illinois, Urbana, Illinois. Accessed November 7, 2008 at http://www.nfcrc.uci.edu/2/UfFC/PowerElectronics/PDFs/04_Pai_Challenge_Part1.pdf
[110]Eynon 2007.
[111]Eynon 2007.

Fault detection and protection may become more difficult with increased distributed generation. As electricity usually flows from areas of high voltage to low voltage, it may become more difficult to detect with fault current coming from both the main power system and from the DG unit.[112] This technical challenge means that in case of fault detection DG units usually are removed from the grid first, which could have business impacts as discussed in the next section.

Electricity storage technical challenges include short lifetimes and environmental issues for batteries and materials properties for flywheels. Flow batteries do have long lifetimes but they have only seen field trials. Nickel metal hybrid batteries also have long lifetimes but have lower energy density.

Sodium-sulfur batteries have shown promise in utility applications but currently too costly. Additionally, the cycle efficiencies of batteries are in the range of 70% to 85% indicating that 15% to 30% percent of energy stored is lost.[113]

M.7.4.2 Business and Financial Challenges

Making the grid compatible with DG systems could be expensive for utilities. There will be a need for instrumentation and communication to make the DG resources dispatchable so that utilities and transmission operators can deal with all the technical issues discussed in the previous subsection. These costs could vary from utility to utility.[114] Please see Metric 3 for a discussion of the Business and Financial challenges presented by a lack of standard interconnection agreements.

Another financial problem posed by storing energy generated by DG resources is that batteries require a large degree of maintenance, which adds significantly to the overall costs of building DG systems, and thus increases the payback period.[115] Unless and until the marginal cost of a battery is less than or equal to the marginal cost of its time-of-use price, viable payback strategies, such as storing power during off-peak periods and selling energy back during high-priced peak periods, will not be feasible and could reduce DG penetration. This is especially true for green power such as wind and solar generation, which can vary during the day.

Distributed generation can be brought online much more quickly than more traditional utility-sized generation, with lower total capital costs. However, the costs per kW are higher and the overall costs of a kilowatt-hour (kWh) produced are usually higher than grid-supplied base-load power. In addition, with the greater flexibility associated with DG comes the risk of less grid stability. When DG is a relatively small amount of the grid, DG's impact is relatively small, but as DG penetration increases, the reliability of the grid could potentially degrade due to voltage fluctuations and reactive-power issues. However, other studies show that when DG is set up properly, greater grid reliability can be achieved since pockets of a smart grid can operate as "islands" in the event of a total grid collapse. Firms may need to take these

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[112] DOE/EIA 2007. *Energy Market Impacts of a Clean Energy Portfolio Standard – Follow-up.*
[113] American Physical Society. 2007. *Challenges of Electricity Storage Technologies.* APS Panel on Public Affairs, Committee on Energy and Environment. American Physical Society, College Park, Maryland. Accessed November 7, 2008 at http://www.aps.org/policy/reports/popa-reports/upload/Energy-2007-Report-ElectricityStorageReport.pdf
[114] U.S. Department of Energy (DOE). 2008. *Metrics for Measuring Progress Toward Implementation of the Smart Grid: Results of the Breakout Session Discussions at the Smart Grid Implementation Workshop, June 19-20, 2008* Office of Electricity Delivery and Energy Reliability. Prepared by Energetics Incorporated. Washington, D.C.
[115] Foote, C.E.T., A.J. Roscoe, R.A.F. Currier, G.W. Ault, J.R. MacDonald. November 18, 2005. "Ubiquitous Energy Storage." 2005 International Conference on Future Power Systems.

considerations into account when evaluating the costs/benefits of buying and providing electricity to their businesses.[116] For example, DG generation may serve as a hedge against grid price fluctuations or power-quality uncertainty: as prices fluctuate upward with tightening supply-demand balances or if power quality begins to fall, DG owners may opt to produce their own electricity.[117]

The use of DG will depend upon the supply and price of alternative fuels. Increasing fuel prices for small combustion generators or the intermittent nature of some renewable energy sources may make the economic feasibility of DG fluctuate and it may not be available to meet short-term needs. However, with flexible pricing schemes, shortfalls in grid-supplied capacity can be mitigated by rising prices.

M.7.5.0 Metric Recommendations

No data were found on the kWh of grid-connected distributed generation. The value may not currently be available, but should be with more advanced metering. In addition, the EIA electric power production information could be improved with an indication of the portion of power production that is dispatchable as opposed to variable resources.

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[116] Driesen, J and R Belmans. 2006.
[117] LeMaire, Xavier, July 6, 2007. "Regulation and Distributed Generation." Presented at the Sustainable Energy Regulation Network/REEEP ERRA Integration Workshop, Budapest, Hungary. Accessed January 13, 2009 at http://www.rec.org/REEEP/workshops/distributed_generation/lemaire_regulation_and_distributed_generation.pdf

Metric #8: Market Penetration of Electric Vehicles and Plug-In Hybrid Electric Vehicles

M.8.1.0 Introduction and Background

This metric examines the penetration of electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) into the light-duty vehicle market. Light-duty vehicles include automobiles, vans, pickups, and sport utility vehicles (SUVs) with a gross vehicle weight rating of 8,500 pounds or less.[118] The PHEV is a hybrid electric vehicle with batteries that can be recharged when plugged into an electric wall outlet and an internal combustion engine that can be activated when batteries require recharging.

The U.S. DOE encourages the development of PHEVs in the U.S. marketplace through its Vehicle Technologies Program. The U.S. DOE supports research into advanced vehicles and fuels, hybrid and electric vehicle systems, energy storage, and materials technology. The U.S. DOE supports the FreedomCAR and Fuel Partnership with the goal of developing emission- and petroleum-free cars and light trucks and supporting infrastructure. Toward the development of PHEVs, the U.S. DOE has established several long-term goals designed to make PHEVs cost competitive by 2014 and ready for commercialization for volume production by 2016:[119]

- $3,400 marginal cost of PHEV technology over existing hybrid technology,
- 40-mile all-electric range,
- 100 miles per gallon equivalent, and
- PHEV batteries that meet industry standards regarding economic life and safety.

Smart grid supports EV and PHEV deployment through real-time pricing structures and bi-directional metering. Real-time pricing would enable customers to recharge vehicles during off-peak hours at reduced cost. Bi-directional metering would enable customers to purchase energy at off-peak hours and sell unused, stored energy back to the utility during peak periods at higher rates. These two elements could feasibly enhance the customer's return on investment (ROI) for EV and PHEV technologies and accelerate market penetration. However, technical challenges with regard to battery performance due to charge and discharge cycles need further investigation and remediation.

M.8.2.0 Description of Metric and Measurable Elements

(Metric 8) The total number and percentage shares of on-road light-duty vehicles - comprising EVs and PHEVs. It also measures EV and PHEV penetration of the light-duty vehicle market, as expressed as a percentage of new vehicle sales.

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[118]The definition of light-duty vehicles includes motorcycles. Although electric motorcycles are commercially available, plug-in hybrid motorcycles are unlikely to be pursued as a product. Therefore, we omitted motorcycles from this analysis.

[119]U.S. Department of Energy (DOE). 2007. *Plug-In Hybrid Electric Vehicle R&D Plan, Working Draft*. DOE, FreedomCAR and Vehicle Technologies Program, Office of Energy Efficiency and Renewable Energy, Washington, D.C.

M.8.3.0 Deployment Trends and Projections

Table M.8.1 presents estimates of EVs and PHEVs currently in use and projected out to 2030 based on the Energy Information Administration's (EIA's) Annual Energy Outlook 2009, Early Release. This outlook is very conservative and does not consider potential future tax credits and other incentives.

The number of EVs operating on-road reached 28,891 in 2006, representing roughly 0.01% of all light-duty vehicles in use. EV sales were small in 2006, representing less than one-tenth of one percent of the light-duty-vehicle market share.[120] The U.S. DOE does not estimate current PHEV sales. There are several companies that perform aftermarket conversions (e.g., Amberjac Systems, Hybrids-Plus, Plug-In Conversions Corp.), but there are no original-equipment manufacturers (OEMs) currently marketing PHEVs. Recent announcements by the automotive industry suggest that PHEVs will be commercially available in the 2010 to 2012 timeframe. PHEV sales are forecast by DOE to reach 237,212 (1.4% of light-duty vehicle sales) by 2020 and 443,207 (2.2% of light-duty vehicle sales) by 2030.

As shown, the number of light-duty EVs in use is forecast to decline in future years to 4,351 by 2030; the decline in EVs in use does not reflect a trend away from alternative vehicle technologies but rather a transition towards more competition among alternative technologies, some of which have not yet entered the marketplace (e.g., PHEVs). The PHEV share of on-road light-duty vehicles is forecast by U.S. DOE to grow slowly through 2030, reaching 4.3 million.[121]

Table M.8.1. EV and PHEV Market Penetration[122]

	EVs On-Road		PHEVs On-Road		EV Sales		PHEV Sales	
Year	Total in Use	% of Light-Duty Vehicles	Total in Use		Total Sales	% of Light-Duty Market	Total Sales	% of Light-Duty Vehicles
2006	28,891	0.01%	-	0.00%	173	0.00%	-	0.00%
2010	24,247	0.01%	35,526	0.02%	130	0.00%	35,526	0.26%
2015	17,840	0.01%	442,570	0.18%	149	0.00%	139,164	0.86%
2020	11,453	0.00%	1,322,438	0.51%	153	0.00%	237,212	1.43%
2025	6,787	0.00%	2,701,419	0.98%	165	0.00%	350,386	1.95%
2030	4,351	0.00%	4,282,767	1.44%	184	0.00%	443,207	2.21%

The U.S. DOE forecast presented in the Annual Energy Outlook is conservative compared to a small number of recent forecasts prepared by industry. While most forecasts estimate ultimate hybrid electric and EV penetration of the light-duty vehicle market in the 8-16 percent range,[123] the Electric Power Research Institute (EPRI) and Natural Resources Defense Council (NRDC) were more aggressive, estimating PHEV market penetration rates under three scenarios, ranging from 20-80% (medium PHEV scenario estimate of 62%) in 2050. EPRI and NRDC used a consumer-choice model to estimate market penetration rates.[124]

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[120] U.S. Department of Energy (DOE). 2009. *Annual Energy Outlook 2008.* Supplemental Tables 57 and 58. DOE, Washington, D.C.
[121] DOE 2009.
[122] DOE 2009.
[123] Greene D, K Duleep, and W McManus. 2004. *Future Potential of Hybrid and Diesel Powertrains in the U.S. Light-Duty Vehicle Market.* ORNL/TM-2004/181. Oak Ridge National Laboratory, Oak Ridge, Tennessee. Accessed November 24, 2008 at http://www.ornl.gov/~webworks/cppr/y2004/rpt/121097.pdf
[124] Electric Power Research Institute (EPRI) and National Resources Defense Council (NRDC). 2007. *Environmental Assessment of Plug-In Hybrid Electric Vehicles – Volume 1: Nationwide Greenhouse Gas Emissions.* EPRI/NRDC, Palo Alto, California. Accessed November 24, 2008 at http://mydocs.epri.com/docs/public/000000000001015325.pdf

A report recently prepared for the U.S. DOE presented and examined a series of PHEV market-penetration scenarios, given varying sets of assumptions governing PHEV market potential. Based on input received from technical experts and industry representatives contacted for the U.S. DOE report and data obtained through a literature review, annual market penetration rates for PHEVs were forecast from 2013 through 2045 for three scenarios. The assumptions underlying the three scenarios are highlighted in Table M.82.

Table M.8.2. PHEV Market Penetration Scenarios

Scenario	Assumptions
Hybrid-Technology-Based Assessment	- PHEV forecast built off existing market forecasts of hybrid technology according to Greene et al. (2004) with PHEV shares of the hybrid market estimated in EPRI and NRDC (2007). - PHEV technology development accelerated as a result of advancements made in hybrid technology.
R&D Goals Achieved	- Delphi approach asking domain experts for their best judgment, given the following conditions: - $4,000 marginal cost of PHEV technology over existing hybrid technology - 40 mile all-electric range - 100 miles per gallon equivalent - PHEV batteries meet industry standards regarding economic life and safety - Tax incentives, regulations and technical standards favor PHEVs.
Supply Constrained	- Infusion of PHEVs in marketplace constrained by automotive and battery manufacturers' ability to meet surging demand. - Existing idle off-peak capacity of electric infrastructure able to meet the demand placed on it by 73% of light-duty vehicles in the U.S.

Under the Hybrid-Technology-Based Assessment scenario, market penetration is forecast to reach 9.7% by 2023 and 11.9% by 2035. Under the R&D Goals Achieved scenario, PHEV market penetration is forecast to ultimately reach 30%, with 9.9% achieved by 2023 and 27.8% reached by 2035. Finally, the Supply-Constrained scenario is forecast to achieve 73% market penetration, with 26.9% reached by 2023, and 68.4% reached by 2035.[125]

The forecasts in Balducci (2008) and EPRI/NRDC (2007) were designed with scenarios based on increasingly aggressive assumptions. These scenarios assume that the PHEV will ultimately become the dominant alternative fuel vehicle. The EPRI/NRDC study was focused on the potential environmental impact of PHEV market penetration. Therefore, aggressive assumptions were required under some of the scenarios to generate a reasonably significant and measurable environmental impact. Neither study presents the scenarios as definitive or assigns probabilities to their outcomes. Rather, the studies are designed to measure the impact, or in the case of Balducci (2008) estimate the penetration rate, given certain sets of assumptions. If the goals outlined in Balducci (2008) are not reached, market penetration rates would certainly be lower than estimated. DOE estimates are generated by the National Energy Modeling System (NEMS), which does not use aggressive assumptions to determine the market potential

[125]Balducci P. 2008. *Plug-In Hybrid Electric Vehicle Market Penetration Scenarios.* PNNL-17441. Prepared for the U.S. Department of Energy by Pacific Northwest National Laboratory, Portland, Oregon.

of PHEVs. Instead, the light-duty alternative fuel vehicle market is forecast by NEMS to be dominated by diesel, flex fuel, and hybrid electric vehicles, not PHEVs.

M.8.3.1 Associated Stakeholders

To date, virtually all EVs have been marketed to public agencies and private companies. Thus, sales to private citizens are negligible. In 2006, 94 percent of all EVs in use were owned by private companies and municipal governments.[126] An additional 4.3 percent were owned and operated by state agencies. The remaining 1.7% were operated by federal agencies, electric utilities, natural gas companies, and transit agencies.[127]

In addition to the fleet operators identified above, stakeholders in the EV and PHEV market space include:

- End users: those who own EVs need straightforward and safe ways to charge their vehicles and be provided with incentives and technology that encourage off-peak charging so that distribution and system capacity constraints are accommodated.
- Electric-service retailers: this group needs to provide consumers with reasonable programs for accommodating EVs. They need to coordinate the constraints on the generation and delivery of electricity and have incentives from the delivery and wholesale power stakeholders to enhance the efficient use of electric resources. Metering and communications mechanisms need to be deployed to meet the needs of the energy products offered.
- Distribution-service providers: the planning and operations of the distribution system need to manage the peaks on EV consumption so capacity constraints are not violated. More distribution system assets will be needed, but encouraging higher asset utilization with greater use of off-peak capacity can mitigate the impacts. Coordinated use of distributed generation, such as solar panels and other forms of local generation need to be included in the distribution system asset mix to address the integration of EVs.
- Transmission providers: As EV penetration strengthens, the bulk power grid will need greater investment as well. As with the distribution system, greater use of off-peak capacity can result in higher asset utilization and help mitigate the impacts.
- Balancing authorities: Charging systems developed with the ability to schedule and respond to emergency system situations can provide new, fast acting resources to system operators. The demand-side, with high-penetrations of EV can provide system reserve resources if deployed appropriately.
- Generation and demand wholesale market operations: EVs whose charging can be scheduled and respond to grid conditions can be aggregated at the wholesale level to provide competition with other generation and demand resources. Market trading products need to be reviewed as penetration levels become significant.

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[126]U.S. Department of Energy (DOE). 2008b. *Alternatives to Traditional Transportation Fuels 2006, Part II.* DOE, Washington, D.C. Table V10.
[127]DOE 2008b.

- Products and services suppliers: This represents a new market area for suppliers. Battery manufacturers, home energy management systems, advanced metering manufacturers, and auto manufacturers are just some of the stakeholders who will look to develop business plans in this area.
- Policymakers and advocates: Policy decisions are needed for funding EV and PHEV research and programs, tax incentives, and establishing the regulatory framework in which the other stakeholders operate. System reliability and cyber security issues become heightened concerns as greater penetration levels are realized.
- Standard organizations: A community of stakeholders from the automotive, power, electrical, mechanical, and software communities needs to coordinate to initiate work on standards that will support the physical and information networking integration of EVs with the electric system.
- Financial community: Venture capital and investment firms will be important players for providing the capital to fund entrepreneurial and regulated utility infrastructure efforts needed to support growth in this area.

M.8.3.2 Regional Influences

In 2006, the five states with the greatest number of EVs operating on-road were California, New York, Massachusetts, Arizona, and Michigan. Today, roughly 54% of all EVs in use are operated in California, reflecting the state's commitment to improving air quality through the adoption of a number of standards and programs (e.g., the Zero Emission Vehicle Program) designed to reduce vehicle emissions.

The market success of EVs and PHEVs is also influenced by regional differences in the prices of electricity and motor fuel. As retail prices for electricity increase relative to the price of gasoline, demand for EVs and PHEVs would be expected to decline. The retail price per kilowatt-hour by state can be reviewed at the U.S. DOE's EIA website at: http://www.eia.doe.gov/fuelelectric.html.

The availability of idle electric capacity is also a regional issue. A study conducted for the U.S. DOE found that electric infrastructure in the U.S. could support the conversion of up to 73% of the light-duty-vehicle fleet to PHEVs without adding more generation and transmission capacity. This figure represents the technical potential and would require strategies for perfect valley-filling of the daily load profile. The availability of electricity in off-peak periods differed by region, with less power available in the Northwest Power Pool Area (10%) and California and Southern Nevada Area (15%), and more power available in the Electric Reliability Council of Texas Area (100%), Mid-Continent Area Power Pool Area (105%), Southwest Power Pool Area (127%), and the area covered by the East Central Area Reliability Coordinating Agreement (104%).[128]

M.8.4.0 Challenges to Deployment

Market penetration generally follows along a logistic-function or s-shaped curve. The market-penetration curve would include a period leading up to the introduction of commercially-viable EVs and

[128]Kintner-Meyer M, K Schneider, and R Pratt. 2007. "Impacts Assessment of Plug-In Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids, Part I: Technical Analysis. In: *Electric Utilities Environmental Conference. The 10th Annual EUEC Conference and Expo. Clean Air, Mercury, Global Warming and Renewable Energy*, Volume 1. Tucson, Arizona. Accessed November 24, 2008 at http://www.euec.com/journal/documents/pdf/Paper_4.pdf

PHEVs; early stages of commercialization, with an evolving technology and new battery and automotive manufacturing facilities being brought on line; ramp-up of production with a mature technology and a significant expansion in the capacity to manufacture and distribute EVs and PHEVs; and finally, full market potential being reached within relevant market constraints. At each stage in the development process there will be technical and financial barriers that must be addressed. These barriers are discussed below.

M.8.4.1 Technical Challenges

Technical barriers include those related to battery technologies, the automotive manufacturing process, supply-chain, refueling and range limitations, and electricity-infrastructure capacity:

- Battery technology limitations include energy intensity, durability, battery life, battery safety aspects, intellectual property (IP) issues, battery size and weight, the cost to manufacture the batteries required to power EVs and PHEVs, and raw material constraints.
- Automotive manufacturing process limitations include incorporation of the weight and space demands of the battery systems; design of instruments to monitor the charge and temperature of the battery system; incorporation of blowers, pumps and other elements into the design process; building of the battery system in to the manufacturing process; re-tooling of plants; and maintenance of vehicle safety.
- Supply chains will need to evolve in order to build suppliers of everything from power transistors to high-density circuit boards. Battery-recycling industry and processes need to be developed. Battery-testing facilities will also need to be expanded to test new battery systems.
- The inability to re-fuel while traveling and significant limitations to the range of all-electric vehicles limit market penetration.
- Approximately 1/3 of all light-duty vehicles park in the street with very limited or no access to a 120 V or 240 V power supply. Infrastructure would need to be developed to provide access to recharging outlets for those customers who live in high-density apartment and condominium complexes.

M.8.4.2 Business and Financial Challenges

Financial and customer-perception barriers include the following:

- The top consumer concerns about hybrid electric vehicles are insufficient power (34%), price (27%), and vehicle dependability (24%).[129] These concerns would transfer to the EV and PHEV marketplace.
- There are driver profiles that do not favor EVs and PHEVs (e.g., heavy use on highways, long commutes, transport of heavy loads).
- Consumers generally require short payback periods and the current cost to convert a hybrid electric vehicle to a PHEV ($6,000-$10,000) would result in a payback period that is unacceptable to most customers.

[129] Greene, Duleep, and McManus 2004.

M.8.5.0 Metric Recommendations

Because PHEVs are receiving increasing attention among industry experts, alternative forecasts of PHEV market penetration are likely to be presented from several sources. These forecasts should be identified and compared against forecasts built into the EIA's Annual Energy Outlook. Some analysis of these alternative forecasts should be performed in order to determine a range of plausible market penetration trajectories.

Metric #9: Grid-Responsive, Non-Generating Demand-Side Equipment

M.9.1.0 Introduction and Background

This metric measures the penetration of demand-side equipment that is responsive to the dynamic needs of the smart grid. The products that have emerged and continue to evolve in this category either directly monitor or receive communicated recommendations from the smart grid. This equipment then provides the useful dynamic responses to those needs either through automated responses or through the conveyance of useful information to consumers who then might appropriately respond. This metric includes only those grid-responsive features that are available on original equipment or by the simple retrofit of existing equipment without needing highly skilled labor. This metric intentionally excludes advanced meters (to be addressed in Metric 12), communications gateways (e.g., home management systems, building automation systems, etc.), equipment that generates or stores electrical energy, and equipment that requires unique engineering for its installation at an endpoint. This excludes much industrial and commercial equipment, except those examples having dynamic grid responses that are supplied on original equipment or by simple retrofit. The metric excludes many "smart" equipment features that target conservation (e.g., occupancy sensors, dirt sensors) or non-energy purposes (e.g., entertainment, security, health).

Examples of grid responsive equipment include communicating thermostats, responsive appliances, responsive space conditioning equipment, consumer energy monitors, responsive lighting controls, controllable wall switches, etc. This category of equipment also encompasses switches, controllable power outlets and various other controllers that could be used to retrofit or otherwise enable existing equipment to respond to smart-grid conditions. For example, a new "smart" refrigerator may be equipped with a device that coordinates with the facility's energy management system to adjust temperature controls, within user-specified limits, based on energy prices. Perhaps a new "smart" surge protector or power strip would communicate with the facility's energy-management system on behalf of the appliances plugged into it. An energy "orb" in a laundry room could advise owners of energy price penalties and opportunities. Consumers whose equipment connects to the internet might remotely receive equipment status updates, energy price updates, and be informed of maintenance issues by email or another message service. The examples are numerous and more will be invented.

The technology exists to implement such grid-responsive equipment; however, there is little standardized supporting infrastructure to communicate with the equipment, nor is there significant demand for it yet, since only approximately 8% of U.S. energy customers now have any form of time-based or incentive-based price structure.[130]

M.9.2.0 Description of Metric and Measurable Elements

This metric tracks the effectiveness and penetration of grid-responsive, non-generating demand-side equipment. The distinction with Metric 5 is that this metric focuses on the original equipment that is equipped to be load more responsive, while Metric 5 addresses benefits achieved from all controllable

[130] Federal Energy Regulatory Commission (FERC). 2008. *Assessment of Demand Response and Advanced Metering.* Staff report. Docket Number AD-06-2-000. Washington, D.C. Accessed November 6, 2008 at: http://www.ferc.gov/legal/staff-reports/demand-response.pdf

loads. The following two measurements have been identified as important to understanding and quantifying grid-responsive, non-generating demand-side equipment.

> *(Metric 9.a) Total U.S. load capacity in each consumer category (i.e., residential, commercial, and industrial) that is actually or potentially modified by behaviors of smart, grid-responsive equipment (MW):* Tracking the influence of new and enhanced "smart" consumer equipment differentiated between residential, commercial, and industrial types defines this metric.

> *(Metric 9.b) Total yearly U.S. retail sales volume for purchases of smart, grid-responsive equipment ($)*: Establishing an overall market-share baseline for these devices will allow analysts to chart device penetration and commercialization success.

M.9.3.0 Deployment Trends and Projections

FERC's 2008 *Assessment of Demand Response and Advanced Metering*[131] estimated about 41 GW of available demand response in the U.S. Only about 8% of customers were on some form of rate- or incentive-based demand-response program. FERC's assessment further breaks this attribution out by region and by customer type. While useful, these numbers are not the same as to the numbers of those proposed for this metric. First, the smart equipment we wish to track could offer features other than traditional demand response. For example, a price-alert signal on a dryer would likely qualify the equipment as smart and responsive to the needs of the grid, but it does not necessarily bring about direct demand response. The FERC numbers also include scheduled voluntary responses (especially for industrial programs) that are communicated by phone or email and do not necessarily use or require any automation and smart equipment.

Programmable, communicating thermostats are a near-term success in this equipment category. Numerous installations of communicating thermostats have been conducted at pilot scale, and full-implementation installations are being launched. The California Energy Commission had planned to require programmable communicating thermostats as part of its 2008 Update to the Building Energy-Efficiency Standards, but had to revise this requirement.[132] It had been projected that the market for communicating thermostats in new California construction could contribute 100,000 new controllable points each year and that that number would be augmented by another 100,000–200,000 thermostats added yearly in existing buildings.[133]

Smart, grid-responsive appliances remain in their commercialization infancy. Trials have occurred in small pilot-scale installations only, where, in most cases, only limited integration of the grid-responsive features has been achieved. For example, the Department of Energy ran a smart-grid experiment on the Olympic Peninsula, Washington, where they tested retrofitted thermostats, water heaters, and clothes dryers fitted with communicating, grid-responsive equipment. The results were promising. The equipment reduced load fluctuations and decreased peak loads and consumer energy costs.[134] As of 2002,

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[131] FERC 2008.

[132] California Energy Commission (CEC). 2008. *California's Energy Efficiency Standards for Residential and Nonresidential Buildings.* Accessed November 17, 2008 at http://www.energy.ca.gov/title24/. Last updated November 13, 2008.

[133] Rosenfeld A. 2005. *Memorandum to Demand Response Planning Meeting Attendees*. Accessed November 17, 2008 at http://www.title24dr.com/PDFs/Demand%20Response%20Memo.pdf

[134] Hammerstrom DJ, R Ambrosio, TA Carlon, DP Chassin, JG DeSteese, RT Guttromson, OM Jarvegren, R Kajfasz, S Katipamula, P Michie, T Oliver, and RG Pratt. 2007. *Pacific Northwest GridWise Testbed Projects:*

through the use of gateway technology pioneered by Salton, Inc. and Microsoft, Westinghouse has manufactured appliances like bread machines and coffee makers that communicate with each other through an alarm-clock-like gateway which synchronizes its schedule and those of all its communication-enabled devices via the internet.[135] Conceivably, these communicating appliances could respond to energy objectives, although they are promoted for consumer convenience and other non-energy objectives. Other manufacturers are developing and testing responsive appliances, too.

Retrofit-able lighting controls have existed for years. Lighting can already be controlled at smart, communicating circuit panels.[136,137] Wirelessly addressable and dimmable fluorescent fixtures have become available for daylight adjustments and for commercial-building demand response.[138,139]

Autonomously responding equipment is also in its infancy. Some large commercial air handlers have been installed with under-frequency or under-voltage responses. Two hundred clothes dryers and water heaters were retrofitted with an autonomous under-frequency response during the Grid Friendly™ Appliance Demonstration.[140] Frequency responses have also been installed via load-control modules (not necessarily fitting our equipment category) and are being installed on refrigerators in the United Kingdom to provide dynamic demand.[141] By 2006, Hawaiian Electric Company, Inc. (HECO) had retrofitted 11,827 electric water heaters with Cooper Power System's Line Under-Frequency (LUF) controllers, representing 8.04 MW of under-frequency-responsive load.[142]

Many residential and commercial aggregators already incorporate web-page information services to utilities and customers as part of their system. Ambient Devices' wireless energy orb was demonstrated in conjunction with PG&E, where the orb color indicated to customers various dynamic electrical energy

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Part 1. Olympic Peninsula Project. Technical Report PNNL-17167, Pacific Northwest National Laboratory, Richland, Washington, October 2007. Available at http://gridwise.pnl.gov

[135]Business Wire. April 22, 2002. *Salton, Inc. Introduces 'Smart' Home Appliances Under the Westinghouse Brand Powered by Microsoft*. Accessed November 18, 2008 at http://www.allbusiness.com/food-beverage/food-beverage-overview/5933350-1.html .

[136]Emerson Climate Technologies. 2003. *Square D Smart Panel Circuit Breaker Control Manual*. 026-1711 Rev 0 6-12-03. Computer Process Controls, Kenesaw GA. Accessed November 17, 2008 at http://www.emersonretailsolutions.com/library/manuals/0261711Rev0.pdf .

[137]Emerson Climate Technologies. 2003. *Cutler-Hammer Smart Breaker Panel Control Manual*. 026-1710 Rev 0 6-10-03. Computer Process Controls, Kenesaw GA. Accessed November 17, 2008 at http://www.emersonretailsolutions.com/library/manuals/0261710Rev0.pdf .

[138]Westinghouse. 2004. *RetroLUX™ T-5 Lighting System*. Westinghouse Lighting Corporation, Philadelphia, PA. Accessed November 17, 2008 at http://www.energysolve.com/Retrolux%20Sell%20Sheet.pdf .

[139]Piette MA and G Ghatikar. 2008. "Linking Continuous Energy Management and Open Automated Demand Response." In Proceedings of *Grid-Interop Forum 2008*, Atlanta, GA, November 11-13, 2008.

[140]Hammerstrom DJ et al. 2007. *Pacific Northwest GridWise™ Testbed Demonstration Projects: Part II. Grid Friendly™ Appliance Project.* Report PNNL-17079, prepared by PNNL for the U.S. DOE. Accessed November 18, 2008 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17079.pdf .

[141]Howe A. 2008. "Introducing Dynamic Demand." In proceedings of *Grid-Interop Forum 2008*, Atlanta, GA, November 11-13, 2008.

[142]Block K, J Layer, and R Rognli. 2007. "Cooper Power Systems Cannon Demand Response Goes Hawaiian. Cooper Power Systems, *The Line*, August 2007. Accessed November 19, 2008 at http://www.cooperpower.com/Library/TheLine/pdf/07_08/Line_HECO.pdf .

price conditions.[143] Whirlpool Corporation demonstrated in its Woodridge Study that appliance consumption could be reduced and deferred by appliance panel indicators and customer feedback.[144]

According to recent interviews conducted for this report (Annex B),

- 45% of responding utilities presently have no automated responses for signals sent to major energy-using equipment
- 45% have some in development
- 10% have a little.

Due to their recent addition to the market, estimates of current smart and web-enabled equipment, as well as forecasts, are hard to obtain. However, due to the convenience, as well as the energy and cost-savings potential of these devices, demand for such devices is expected to increase as the supporting infrastructure becomes available.

M.9.3.1 Associated Stakeholders

Associated stakeholders include:

- End users: incentives to reduce electricity bills as peak-demand electricity prices rise;
- Balancing authorities and reliability coordinators: frequency-responsive devices can greatly benefit the grid during stressed conditions and prevent blackouts;
- Product and service providers: they are interested if there is a market. Appliance manufacturers will have an obvious role to play in providing the market with competitive and high-quality "smart" solutions and should welcome an opportunity to compete by providing better grid services than do their competitors;
- Policymakers: incentives to create a more reliable grid.

M.9.3.2 Regional Influences

These devices will be expected to meet the same standards that non-smart devices are required to meet in terms of energy use, safety, and other regional parameters.

The evolution of smart-grid devices will be heavily influenced by the way energy programs are offered and enacted. Energy programs tend to be localized and regional; however, smart-grid devices will be most economically manufactured for a larger national, or even global, customer set. Cost-effective application of smart-grid devices will be difficult to attain without much standardization.

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[143] Ambient Devices. 2008. *PG&E Demand-Response Orb*. Accessed November 17, 2008 at http://www.ambientdevices.com/cat/orb/PGE.html

[144] Horst GR. 2006. *Whirlpool Corporation Woodridge Energy Study and Monitoring Pilot.* Whirlpool Corporation. Accessed November 17, 2008 at http://www.ucop.edu/ciee/dretd/documents/Woodridge%20Final%20Report.pdf

M.9.4.0 Challenges to Deployment

Smart, grid-responsive equipment faces significant implementation challenges. As was succinctly stated by Arthur Rosenfeld, Commissioner, CEC, in a 2005 memorandum concerning programmable, communicating thermostat programs in California, "We perceive that the barriers to increased market penetration include relatively high costs of hardware installation, no plug-and-play capabilities, lack of a universal communication protocol to send price or emergency signals, and a lack of product availability at big box retailers."[145]

M.9.4.1 Technical Challenges

Among the biggest challenges facing these devices are technical considerations. Implementing communication interfaces in modern appliances requires significant investments into hard-, soft-, and firm-ware design.[146] Memory considerations such as the amount of data storage and networking options are an important concern. Other hardware considerations include accommodating diverse operating environments such as temperature and water exposure. Further decisions will have to be made regarding communications options. "Wired" networking options have costs and performance characteristics different from those of "wireless" networking options.

M.9.4.2 Business and Financial Challenges

Currently there is significant interest in this field. Businesses such as LG Electronics and Westinghouse are designing and producing more "web-enabled" household appliances. Research and development in these fields will poise producers to easily transition into "smart" devices. However, incorporating electronics into increasing numbers of appliances, as well as developing and maintaining software for these appliances, will require a new look at the products' life-cycle costs. Manufacturers and grid entities have not yet settled on standards that would give manufacturers the confidence necessary to fully integrate and launch grid-responsive equipment. Perhaps this is because the business case for integration of these features has not yet been fully proven.

M.9.5.0 Metric Recommendations

The smart equipment discussed in this metric remains in its infancy. New examples continue to emerge. Consequently, the definition of which equipment should and should not be counted in this metric should also be expected to evolve in the next few years. An issue in defining this metric is the emphasis on residential appliances. Commercial building and industrial equipment with embedded, grid-responsive capability deserves to be more closely scrutinized in future investigations.

Today, the numbers of responsive equipment of other types are overwhelmed by the relative commercial success of communicating thermostats. This metric may be more meaningful if it were separated from the rest, leaving a catch-all category for other grid-responsive equipment that is in a much less mature state of commercialization.

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[145] Rosenfeld. 2005.

[146] Eckel C, G Gaderer, and T Sauter. 2003. "Implementation Requirements for Web-Enabled Appliances – a Case Study." In *2003 IEEE Conference on Emerging Technologies and Factory Automation Proceedings (ETFA 2003).* Vol 2, pp. 636-642. Institute of Electrical and Electronics Engineers, Piscataway, New Jersey. Accessed November 18, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=1248758&isnumber=27958

Secondary information sources were not readily found for estimating penetration of responsive equipment. More effort is required to accurately quantify the penetration of responsive equipment. In two years, pilot installations of responsive-equipment examples should be more readily compiled.

Metric #10: Transmission and Distribution Reliability

M.10.1.0 Introduction and Background

This section examines the transmission and distribution (T&D) reliability value metric. As a value metric it will be difficult to establish which smart-grid attributes enhance or degrade the measurement, but features such as T&D automation are intended to enhance T&D reliability. There are over 700,000 miles of transmission lines and one million miles of distribution lines in the United States. The U.S. T&D system has been under scrutiny due to recent widespread outages, such as the 2003 New York City blackout and the California energy crisis. Approximately 80 to 90 percent of end-user outages can be traced to problems in the distribution system, most of which are caused by equipment malfunctions, such as a transformer failure, or by physical damage to distribution plants, such as a tree branches on power lines. Transmission-line problems account for only 10 to 20 percent of outages, but these include the largest and most costly events.[147] The Electric Power Research Institute (EPRI) in 2001 estimated power-interruption and power-quality cost at $119 billion per year,[148] and a 2004 study from Lawrence Berkeley National Laboratory (LBNL) estimated the cost at $80 billion per year.[149]

Smart-grid technologies will address transmission congestion issues through demand response and controllable load. Smart-grid-enabled distributed controls and diagnostic tools within the transmission system will help dynamically balance electricity supply and demand, thereby helping the system respond to imbalances and limit their propagation when they occur. These controls and tools could reduce the occurrence of outages and power disturbances attributed to grid overload. They could also reduce planned rolling brownouts and blackouts like those implemented during the energy crisis in California in 2000. Smart-grid technologies could also quickly diagnose outages due to physical damage of the transmission and distribution facilities due to weather and could direct crews to repair them quickly.[150]

M.10.2.0 Description of Metric and Measurable Elements

Several widely accepted metrics for measuring T&D reliability already exist in the industry. The System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI) describe the duration and frequency of sustained interruptions experienced by customers of a utility in one year.[151] These metrics are the focus of this paper.

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[147] Hamachi LaCommare, K and J Eto. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. Lawrence Berkeley National Laboratory (LBNL). LBNL-55718, LBNL, Berkeley, California. Accessed October 14, 2008 at http://certs.lbl.gov/pdf/55718.pdf

[148] Electric Power Research Institute (EPRI), 2001. *The Cost of Power Disturbance to Industrial and Digital Economy Companies.* Consortium for Electric Infrastructure to Support a Digital Society. Prepared by Primen for EPRI. Accessed October 15, 2008 at http://www.epri-intelligrid.com/intelligrid/docs/Cost_of_Power_Disturbances_to_Industrial_and_Digital_Technology_Companies.pdf

[149] Hamachi LaCommare and Eto 2004.

[150] Baer WS, B Fulton, and S Mahnovski. 2004. *Estimating the Benefits of the GridWise Initiative: Phase I Report.* TRI-160-PNNL, Prepared by Rand Science and Technology for the Pacific Northwest National Laboratory. Accessed October 15, 2008 at http://www.rand.org/pubs/technical_reports/2005/RAND_TR160.pdf.

[151] Institute of Electrical and Electronics Engineers (IEEE). *IEEE Recommended Practice for Monitoring Electric Power Quality.* IEEE Standard 1159-1995, IEEE, Inc., Piscataway, New Jersey.

(Metric 10.a) SAIDI represents the average number of minutes customers are interrupted each year, and is calculated as

$$SAIDI = \frac{\text{Sum of customer (sustained) interruption durations for all customers}}{\text{Total number of customers served}}.$$

(Metric 10.b) SAIFI represents the total number of customer interruptions per customer for a particular electric supply system, and is calculated as

$$SAIFI = \frac{\text{Total number of customer (sustained) interruptions for all customers}}{\text{Total number of customers served}}.$$

(Metric 10.c) CAIDI represents the average outage duration that a customer experiences; alternatively stated, it is the average restoration time.

$$CAIDI = \frac{\text{Sum of durations of all customer interruptions}}{\text{Total number of customer interruptions}} = \frac{SAIDI}{SAIFI}$$

(Metric 10.d) MAIFI represents the total number of customer interruptions per customer lasting less than five minutes for a particular electric supply system, and is calculated as

$$MAIFI = \frac{\text{Total number of momentary (< 5 min) interruptions for all customers}}{\text{Total number of customers served}}.$$

M.10.3.0 Deployment Trends

A recent study by LBNL on the cost of T&D reliability incidents compared several different studies that examined national statistics on SAIDI, SAIFI and MAIFI. The findings are presented in Table M.10.1. LBNL also compiled data and calculated trimmed means at the regional level. These regional indices are shown in Table M.10.2.

Table M.10.1. Summary of U.S. Reliability Event Estimates[152]

	SAIFI	SAIDI	MAIFI
EPRI Report	1.1	107	
IEEE 1995 Survey	1.3	120	5.5
EEI Annual Report			
1998	1.2	118	5.4
1999	1.4	101	11.6

[152] Hamachi LaCommare and Eto 2004.

Table M.10.2. Regional Variation in Collected Reliability Event Data[153]

Region #	Region Name	SAIDI	SAIFI	MAIFI
1	New England	131	1.1	N/A
2	Middle Atlantic	115	1.0	9.5
3	East North Central	N/A	N/A	N/A
4	West North Central	63	0.8	11.2
5	South Atlantic	N/A	N/A	N/A
6	East South Central	N/A	N/A	N/A
7	West South Central	95	1.3	N/A
8	Mountain	92	1.1	3.5
9	Pacific	105	1.2	3.2
10	California	138	1.3	2.3
U.S.	U.S.	106	1.2	4.3

The IEEE's 2005 benchmarking study[154] analyzed data from 55 companies between 2000 and 2005. Results showed an 8% increase in CAIDI, a 21% increase in SAIDI and a 13% increase in SAIFI. The national trend is shown in Figure M.10.1.

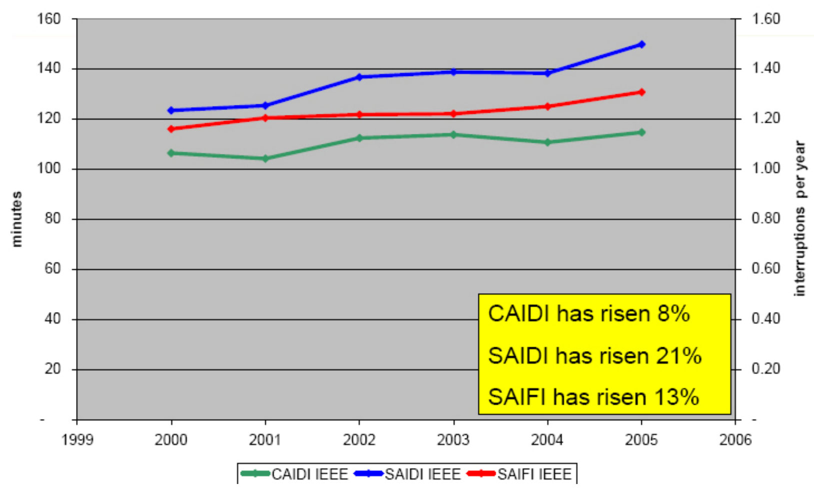

Figure M.10.1. Trends for 55 Utilities Providing Data Between 2000-2005[155]

The smart-grid interviews conducted for this report asked utilities to present SAIDI, SAIFI, and MAIFI data for the most recent year for which data were available and compare actual data against the levels predicted prior to the year in question. Findings from the interviews are summarized in Table M.10.3. Responses from each utility were weighted based on their share of the total customer base of those utilities providing data.

153 Hamachi LaCommare and Eto 2004.

154 Institute of Electrical and Electronics Engineers (IEEE). 2006. *IEEE Working Group on Distribution Reliability, Benchmarking 2005 Results*. July 2006. Accessed October 15, 2008 at http://grouper.ieee.org/groups/td/dist/sd/doc/2006-07-BenchmarkingUpdate.pdf.

155 IEEE 2006.

Table M.10.3. Predicted and Actual SAIFI, SAIDI, and MAIFI

Metric Name	Predicted	Actual
SAIFI	1.2	1.3
SAIDI	132.5	158.9
MAIFI	8.4	4.6

The North American Electric Reliability Council's 2007 Long Term Reliability Assessment found that summer peak demand in the U.S. is forecast to increase over 135,000 MW or 17.7 percent in the next ten years, with committed resources projected to increase 77,000 MW or 8.4 percent (including uncommitted resources, 123,000 MW or 12.7 percent).[156] Their U.S. Capacity Margin Comparison, shown in Figure M.10.2, shows the U.S. capacity margins declining throughout the ten-year period.

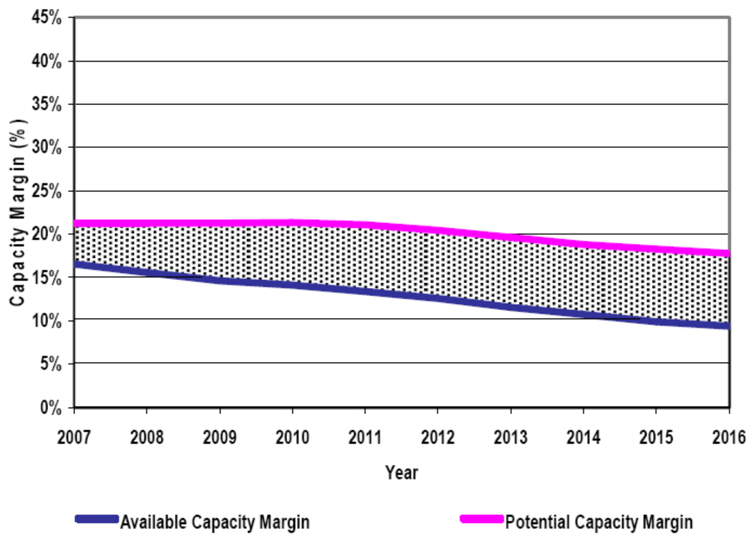

Figure M.10.2. U.S. Capacity Margin Comparison – Summer[157]

M.10.3.1 Associated Stakeholders

There are a number of stakeholders with interests in transmission and distribution reliability:

- Electric-service retailers wanting to cost-effectively provide a more reliable product
- End users (consumers) needing consistent reliable power
- Local, state, and federal energy policymakers concerned with the negative economic effects of poor power quality on commercial and industrial customers
- Regulators who decide the basic level of power quality and reliability that the system will provide to customers.

[156]North American Electric Reliability Council. 2006. *2006 Long-Term Reliability Assessment: The Reliability of the Bulk Power Systems in North America.* Accessed November 24, 2008 at http://www.nerc.com/files/LTRA2006.pdf
[157]NERC 2006.

M.10.3.2 Regional Influences

Reporting regulations and practices vary from state to state, making it difficult to compare data such as the above-mentioned metrics across regions. Regional differences arise for several reasons such as climate, geography, and design and maintenance of the distribution system. Some utilities will naturally have better reliability indices than others due to differences in frequency and types of severe weather, geography and natural vegetation in the region. For example, the number of lightning strikes, the length of exposed feeders, and urban network-system designs have a significant impact on reliability figures, regardless of the utilities' ability to operate and maintain their systems.[158] Each region of the country has a different combination of number and type of customers (residential, commercial, and industrial) and each utility has its own unique distribution system, all of which affect T&D reliability.

The 2006 National Electric Transmission Congestion Study conducted by the U.S. DOE investigated the eastern and western interconnections to identify constrained transmission paths of national interest. Transmission congestion can indicate areas of system stress that can impact reliability as well as the cost of electricity. Using scenarios projecting fuel prices for 2008 and 2011, the study identified 118 paths in the eastern interconnection that would be congested under almost every scenario. The western analysis modeled significantly larger nodes than the east and identified 10 paths that were likely to be the most heavily congested in their 2008 projections as ordered by the number of hours when usage is 90% or greater of a line's limit. Overall, the study identified two critical congestion areas: 1) the Atlantic coastal area from New York to northern Virginia, and 2) Southern California. Four congestion areas of concern were also identified (one in the east and three in the west). Five conditional congestion areas were also listed as situations to watch. It should be noted that the U.S. DOE did not include the Electric Reliability Council of Texas (ERCOT) in their study because it was explicitly excluded in their directive from Energy Policy Act of 2005.[159]

Electricity trading patterns and transmission congestion are different in the West than in the East for several reasons. First, the transmission system in the West was built primarily to carry power over long distances. Several large power plants in the West were intentionally built in remote locations where owners constructed high-voltage transmission lines to ship power to densely populated load centers. Also, the Pacific Northwest uses a great deal of hydroelectric power, which is greatest in the spring and summer, while demand in the region is greatest in the winter. Therefore, the Pacific Northwest sells its excess capacity in the spring and summer to California and other western states, and purchases excess supply from the same regions in the winter.

The Northeast blackout of 2003 affected 8 U.S. states in the Northeast and one Canadian province, leaving 50 million people without power for up to two days in some places. Twelve airports had to be shut down, leading to 700 canceled flights, and all trains in the New York City area came to a halt, stranding people in the city for the night. A joint commission of U.S. and Canadian representatives later

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[158] Kueck JD, BJ Kirby, PN Overholt, and LC Markel. 2004. *Measurement Practices for Reliability and Power Quality: A Toolkit of Reliability Measurement Practices*. Oak Ridge National Laboratory (ORNL), ORNL/TM-2004/91, ORNL, Oak Ridge, Tennessee. Accessed October 14, 2008 at http://www.ornl.gov/sci/engineering_science_technology/eere_research_reports/power_systems/reliability_and_power_quality/ornl_tm_2004_91/ornl_tm_2004_91.pdf

[159] U.S. Department of Energy (DOE). 2006. *National Electric Transmission Congestion Study.* Accessed May 27, 2009 at http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf

traced the cause of the blackout to Ohio, where trees had not been cut back away from the power lines. It is estimated that the economic activity lost due to the blackout was between $4.5-12 billion.[160]

In 2000, California prepared a response to an electricity shortage situation by enacting legislation that introduced the "rolling blackout," which intentionally and systematically shuts down areas of peak demand for up to several hours (60 minutes to 2.5 hours) while the rest of the local or regional grid is equalized. If the grid is unstable after the first grid is blacked out, they will bring the first grid back online and black out the second grid, and so on, until the grid is stabilized. California customers' electric bills include the number of the power grid (1 through 14) to which they belong, giving the customers an idea of when their electricity will be turned off during rolling blackouts.[161,162]

M.10.4.0 Challenges to Deployment

M.10.4.1 Technical Challenges

Technical challenges include combining new technologies with the existing grid and updating the existing grid. Unique characteristics of wind, solar, and nuclear power generation must be taken into account when planning for the future. A recent NERC survey of industry professionals ranked aging infrastructure and limited new construction as the number one challenge to reliability—both in likelihood of occurrence and potential severity. Lastly, more standardized codes, requirements and reporting of T&D reliability are needed.[163]

M.10.4.2 Business and Financial Challenges

Upgrading and adding to the grid incurs costs that some may be cautious to take on. FERC, in a policy statement on matters related to bulk power system reliability, stated that public utilities may be reluctant to spend significant amounts of money without reassurance that they will be able to recover it. The report goes on to note:

> *"Regulators should clarify that prudent expenditures and investments to maintain or improve bulk power system reliability will be recoverable through rates. The Commission also assures public utilities that they will approve applications to recover prudently incurred costs necessary to ensure bulk electric system reliability, including prudent expenditures for vegetation management, improved grid management and monitoring equipment, operator training, and compliance with NERC reliability standards and Good Utility Practices."*[164]

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[160] U.S. Department of Energy (DOE). 2004. *National Electric Delivery Technologies Roadmap: Transforming the Grid to Revolutionize Electric Power in North America.* Office of Electric Transmission and Distribution, Washington, D.C. Accessed October 15, 2008 at http://www.oe.energy.gov/DocumentsandMedia/ER_2-9-4.pdf

[161] Galvinpower.org. October 2006. *Blackout the microgrid solution.* Access February 6, 2009 at http://www.galvinpower.org/files/Blackouts_the_microgrid_solution.doc

[162] Coleman**,** Jennifer**.** April 16, 2004**.** *California faces repeat of deregulation debate.* Associated Press**.** Accessed February 6, 2009 at http://www.ontariotenants.ca/electricity/articles/2004/ap-04d16.phtml

[163] Federal Energy Regulatory Commission (FERC). 2007. *Results of the 2007 Survey of Reliability Issues.* 107 FERC 61,052, October 24, 2007, FERC, Washington, D.C., April. Accessed February 6, 2009 at http://www.nerc.com/files/Reliability_Issue_Survey_Final_Report_Rev.1.pdf

[164] Federal Energy Regulatory Commission (FERC). 2004. *Policy Statement on Matters Related to Bulk Power System Reliability*. 107 FERC 61,052, Docket No. PL04-5-00 2004. Issued April 19, 2004, FERC, Washington, D.C., April. Accessed October 14, 2008 at http://www.ferc.gov/whats-new/comm-meet/041404/E-6.pdf

A large portion of the utility workforce is approaching retirement without a skilled workforce to take their place. Utilities need to actively recruit and train skilled labor to ensure a knowledgeable workforce for the future. Lastly, educating and demonstrating to the end users the use of smart-grid enabled programs, such as dynamic pricing, should be a priority.

Currently, there are irregularities in the ways utilities and regions report T&D reliability incidents. Definitions are sometimes vague, and inconsistencies in reporting requirements are making it difficult to complete analyses. For example, SAIDI, SAIFI, and MAIFI are useful for assessing T&D reliability, but often are not collected or are collected inconsistently.[165] In a 2003 nationwide study by IEEE, several inconsistencies between utility practices were found. They found disparity in how start and end times of an interruption are reported, wide discrepancies in what defines a major event that would be excluded from reliability indices, and some utilities include MAIFI within SAIFI, which inflates SAIFI. Utilities vary on what level they measure reliability (i.e., substation, circuit breaker, meter, transmission, etc.), and interruption data is entered differently, either automatically by a computer or manually.[166]

M.10.5.0 Metric Recommendations

More interviews should be conducted in support of future smart-grid benchmark studies and a single data source should be identified for national statistics covering SAIDI, SAIFI, CAIDI and MAIFI. Support for a single source would allow analysts to compare trends over time in a consistent manner.

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[165]Kueck et al 2004.

[166]Warren CA, DJ Pearson, and MT Sheehan. 2003. "A Nationwide Survey of Recorded Information used for Calculating Distribution Reliability Indices." *IEEE Transactions on Power Delivery* 18(2):449-453. DOI: 10.1109/TPWRD.2002.803693 Accessed November 26, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=1193863&isnumber=26850

Metric #11: Transmission and Distribution Automation

M.11.1.0 Introduction and Background

T&D automation is defined by the IEEE as "a system that enables an electric utility to remotely monitor, coordinate, and operate [transmission and] distribution components in a real-time mode from remote locations." This metric includes coordination between electric T&D components that are separate but co-located. This broad definition encompasses a large set of technologies, which includes SCADA technologies, remote sensors and monitors, switches and controllers with embedded intelligence, digital relays, and a large number of other technologies used in the T&D infrastructure. The general operating scheme of these devices is to gather real-time information about the grid through communication and coordination with other devices, process the information on site, take immediate corrective action if necessary, and communicate results back to human operators or other systems. These devices serve a variety of functions, including "fault location, fault isolation, feeder reconfiguration, service restoration, remote equipment monitoring, feeder load balancing, Volt-VAR controls, remote system measurements, and other options."[167] If operated properly, transmission and distribution automation systems can provide more reliable and cost-effective operation through increased responsiveness and system efficiency.

M.11.2.0 Description of the Metric and Measurable Elements

The metric for automation technology adoption are defined as:

(Metric 11) Percentage of substations having automation

M.11.3.0 Deployment Trends and Projections

Data from utilities across the nation show a clear trend of increasing T&D automation and increasing investment in these systems. Key drivers for the increase in investment include operational efficiency and reliability improvements to drive cost down and overall reliability up. The lower cost of automation with respect to T&D equipment (transformers, conductors, etc.) is also making the value proposition easier to justify. With higher levels of automation in all aspects of the T&D operation, operational changes can be introduced to operate the system closer to capacity and stability constraints.

Results of interviews undertaken for this report (see Annex B) indicate that:

- 28% of the total substations owned were automated
- 46% of the total substations owned had outage detection
- 46% of total customers had circuits with outage detection
- 81% of total relays were electromechanical relays
- 20% of total relays were microprocessor relays

Other nationwide data has shown that transmission automation has already penetrated the market highly, while distribution automation is primarily led by substation automation, with feeder equipment automation still lagging. Recent research shows that while 84% of utilities had substation automation and integration plans underway in 2005, and about 70% of utilities had deployed SCADA systems to

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[167]Uluski, R. 2007. "Is Distribution Feeder Automation Right for You and Your Customers?" *EnergyPulse.* May 21, 2007. Accessed October 28, 2008 at: http://www.energypulse.net/centers/article/article_print.cfm?a_id=1481.

substations, the penetration of feeder automation is still limited to about 20%.[168,169] Because feeder automation lags other automation efforts so significantly, this should be an area addressed directly in future work.

It is worth noting that aside from the survey data which is presented here, there is a relative lack of data about the penetration of transmission and distribution automation. Differences in how these devices are operated make it difficult to directly draw conclusions about the impact of these devices on the actual performance of the grid.

A significant component of the measurement, analysis, and control of the T&D infrastructure relates to control centers at the transmission and distribution levels of the system (SCADA, energy management systems – EMS, and distribution management systems - DMS). According to a recent survey by Newton-Evans Research, almost all utilities with over 25,000 customers have SCADA/EMS systems in place, while only about 17% of utilities have DMS systems.[170] One smart grid trend is to integrate other functions with these centers. For example, about 30% of the SCADA/EMS systems are linked to Distribution Automation/DMS. Figure M.11.1 shows the projected integration of EMS/SCADA/DMS systems to a variety of other data systems.

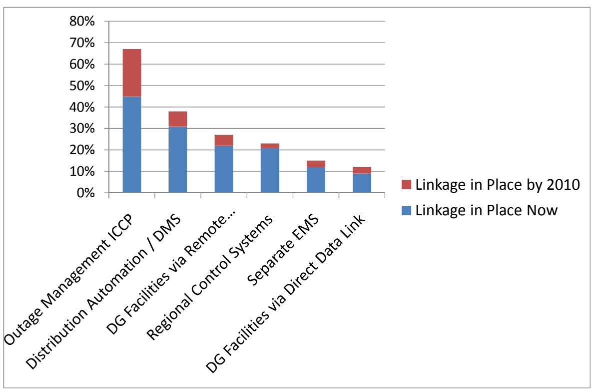

Figure M.11.2. Current/Future Plans for Connecting EMS/SCADA/DMS Systems to Other Data Systems[171]

[168]*T&D Automation News*. Electric Light and Power. Accessed November 21, 2008 at: http://uaelp.pennnet.com/resource/transmission%20and%20distribution

[169]D McDonnell. 2006. "Beyond the Buzz: The Potential of Grid Efficiency." *Smart Grid News*. Accessed November 21, 2008 at: http://www.smartgridnews.com/artman/publish/industry/Beyond_the_Buzz_The_Potential_of_Grid_Efficiency_180_printer.html.

[170]Newton-Evans Research Company. 2008. *Market Trends Digest,* 3rd Quarter 2008 Edition. Newton-Evans Research Company, Endicott City, Maryland. Accessed November 11, 2008 at: http://www.newton-evans.com/mtdigest/mtd3q08.pdf

[171]Newton-Evans 2008.

The investment in T&D automation can be estimated either from total industrial output of specific automation products to U.S. markets or from the receiving demand side (utility company) as purchases. Market statistics for T&D investment already exist and could be readily utilized. Newton-Evans Research provides market-volume estimates on automation products aggregated to categories such as shown in Figure M.11.2 below. The figure shows that significant increases in T&D automation are expected between 2007 and 2010. For example, spending on distribution automation is expected to almost triple by 2010 to nearly $180 million. Protective relays are expected to increase 25% to $235 million, feed-switch investment by 225% to $65 million, control-center upgrades by 29% to $155 million; and substation investment by 35% to $540 million.[172]

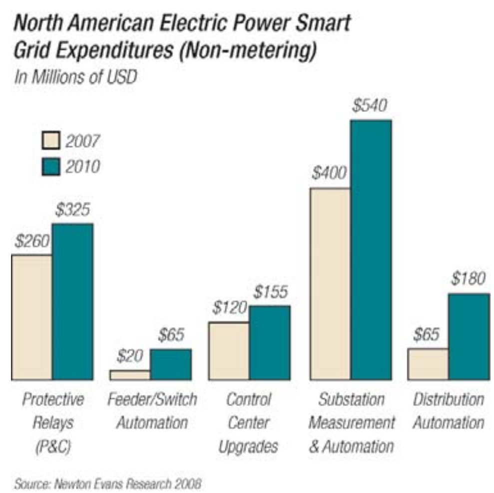

Figure M.11.2. North American Electric Power T&D Automation Expenditures (in Millions of USD)[173,174]

M.11.3.1 Stakeholder Influences

The major stakeholders in the T&D automation arena are those that are directly affected by the performance of this infrastructure including:

- Transmission providers as owners and operators of the assets to be maintained and upgraded.
- Distribution-service providers as owners and operators of the assets to be maintained and upgraded.
- Local, state and federal energy policy makers: local governments as regulatory entities for publicly owned companies; state regulators as regulatory entities for investor-owned T&D companies; federal regulators as enforcement entities for reliability. For investor-owned T&D companies, state regulators as regulatory entities approving rate structures.
- Financial community: the financial community will need to provide capital for the required upgrades.
- Reliability coordinators: ensuring that electricity quality and reliability are maintained.

[172]Newton-Evans 2008
[173]Newton-Evans 2008.
[174]Ockwell G. 2008. "The Smart Grid Reaches Main Street USA". *Utility Automation & Engineering T&D*. 13(5). Accessed October 28, 2008 at: http://uaelp.pennnet.com/display_article/328726/22/ARTCL/none/none/1/Th

- Balancing authorities, who will benefit from utilization and efficiency in the delivery system.
- End users: consumers, who stand to gain from more cost-effective reliability.

M.11.3.2 Regional Influences

While transmission is relatively homogeneous nationwide, distribution networks vary widely among utilities. Utilities differ in the design and sizing of distribution-system components, which manifests itself in the level of system loading. Some utilities maintain their feeders at a maximum of 50% loading, allowing a single other line to pick up the load of a failed feeder. Others allow their feeders to reach 66% loading or 100% loading, reflecting different operation and contingency schemes.[175] Some of these differences are due to historical or institutional reasons within the utility. Other differences are driven by regulators or by state policy. These characteristics will significantly change the business case for automation.[176]

For example,

- The highly dense urban core of New York City's mesh distribution network, with its demand for reliable power, lends itself to distribution-automation systems.[177,178]
- The long rural feeders of West Virginia, which require hours of driving for utility linemen, are good candidates for remote monitoring and control.[179]
- The well-connected network system and radially operated distribution grid of San Diego lends itself to automatic fault-detection and feeder-reconfiguration schemes.[180]

In addition, there are significant differences in the vintages of the distribution system, primarily determined by economic growth in different regions of the country. Southwestern and Southeastern regions have seen significant load growth in the last decades, which led to new T&D expansions with more modern technology. In contrast, established East Coast and Midwestern cities tend to have dated system components that are a half-century old or more.

M.11.4.0 Challenges

M.11.4.1 Technical Challenges

Challenges in T&D automation for transmission differ from those for distribution. Methods for transmission-side automation are fairly well known, but deployment is challenged by funding and

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[175] Personal communications with Kevin Schneider. Pacific Northwest National Laboratory. November 4, 2008.
[176] Moore D and D McDonnell. 2007. *Smart Grid Vision Meets Distribution Utility Reality*. The McDonnell Group. Accessed November 11, 2008 at http://www.themcdonnellgroup.com/media_center/inprint/SmartGridVision_Opinion.pdf
[177] Ross MP and B Kehrli. March 2008. *Secure Super Grids™: A New Solution for Secure Power in Critical Urban Centers*. Institute of Electrical and Electronics Engineers (IEEE). IEEE Xplore. Accessed November 11, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=04517197.
[178] Advanced Control Systems. *Case Studies.* Accessed November 24, 2008 at http://www.acsatlanta.com/pages/sd_list.html . Last updated September 30, 2008.
[179] Personal communications with Kevin Schneider. Pacific Northwest National Laboratory. November, 04, 2008.
[180] Advanced Control Systems. *Case Studies*.

institutional barriers.[181] Distribution-side automation has seen an influx of new technologies, some of which are not very well understood. There are few existing options for modeling the effects of these new technologies on utilities, and thus the business case for these devices is more difficult to sell. Many utilities, which traditionally have not had digital systems for managing their networks, are finding that the transition to automated T&D systems is expensive. This is because large-scale renovations are needed to install the prerequisite sensing and monitoring systems. Proving the value of these technologies through demonstration projects is an important first step toward gaining industry and regulatory acceptance. As with transmission automation, however, institutional barriers must be removed before high-level acceptance of this technology can foster widespread deployment.

M.11.4.2 Business and Financial Challenges

Deployment of new distribution-automation technology requires business-case analysis support for both the utility and the regulator. While advanced tools now exist for technology-savvy utilities, it is still difficult to model and justify these investments at a higher level. Standard business-case tools for utilities and regulators should be developed to expedite the analysis of these projects and verification of their value.

M.11.5.0 Metric Recommendations

In future reports, the indicative metric should be reviewed against two types of metrics: the first consists of directly measurable or numeric estimates; the second set consists of qualitative elements. Qualitative metrics describe how automation components are used. A few metrics can be chosen from the many described below.

The quantitative metrics consist of an estimation of the rate of deployment of technology and automation, and the amount of investment for automation products to capture the economic activity.

(11.a) Percentage of substations having automation (the metric used for this report)
(11.b) Percentage of substations with outage detection
(11.c) Percentage of circuits with fault-detection and -localization capabilities
(11.d) Number of automated Substations
(11.e) Number of electromechanical relays
(11.f) Number of microprocessor relays
(11.g) Number of intelligent electronic devices (IEDs) deployed
(11.h) Percentage of distribution circuits with sectionalization and reconfiguration capabilities
(11.i) Percentage of distribution circuits with feeder load-balancing strategies

The investment metrics are defined as annual expenditures in dollars for:

(11.j) Protective relays
(11.k) Feeder/switch automation
(11.l) Control-center upgrades
(11.m) Substation measurement and automation
(11.n) Distribution automation

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[181] *EnergyBiz* Magazine. 2006. "Guide & Sourcebook. Transmission & Distribution Automation." January/February 2006, pp 51-66. Accessed October 28, 2008 at: http://energycentral.fileburst.com/Sourcebooks/gsbk0106.pdf

Based on Sheridan's scale for degree of automation, the following qualitative metrics are suggested:[182]

- *(11.o)* Operational T&D control action performed manually by linemen or operators in central control centers
- *(11.p)* Distributed electronic and computing devices detect normal and fault conditions and offer a set of action options
- *(11.q)* Intelligent electronic devices (IEDs) narrow the options down to a few, or suggest one. For instance, system fault localization and suggestions for fault isolation and feeder reconfiguration
- *(11.r)* IED recognizes a fault and executes a suggestion after operator/human approval. For instance, IEDs support an overarching control strategy that performs immediate remedial actions such as feeder reconfiguration and autonomous system restorations
- *(11.s)* IED recognizes fault, then executes remedial actions automatically and informs operator after execution.

Because of its qualitative nature, assigning an appropriate scale to the degree of automation for any particular segment of the grid requires a judgment call. To assess the level of automation deployment it is recommended to use a set of quantitative metrics that capture a) the level of adoption of automation technology and b) the level of investment as indicator of a rate of change in the penetration of automation in the U.S. grid. Furthermore, a qualitative metric that describes the level of control autonomy of the automation products and the degree to which automation strategies can be executed without human interventions or interactions should be considered.

The metrics are only useful if data exist or can be collected at a cost low enough to allow tracking of the metrics over time. For this particular T&D automation assessment, we interviewed 21 service providers to collect a representative sampling of the data. In the future, the Edison Electric Institute (EEI) could function as an intermediary to the investor-owned companies; for the publicly owned entities, the Public Power Association could be consulted as a potential intermediary for collecting data from the over 3000 public T&D organizations. Note that progress in this area is difficult to accurately assess with respect to improvements over time. The total number of substations or total industry output figures for T&D automation products is only a crude indicator of the technological progress that will certainly continue into the coming decades.

[182]Sheridan TB. 1992. *Telerobotics, Automation and Human Supervisory Control*. MIT Press, Cambridge, Massachusetts.

Metric #12: Advanced Meters

M.12.1.0 Introduction and Background

A source of growing interest for utility and government agencies is advanced meters and their supporting infrastructure, or AMI, with ever-increasing numbers of utilities submitting propositions to their public utility commissions and increasing funding for AMI deployments. For our purposes, we will use the FERC Demand Response Assessment[183] definition of AMI that states, "Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."

However, AMI technology has also come to mean the ability to communicate real-time pricing data, grid conditions, and consumption information. Such data dramatically increase the accuracy of pricing policies and demand forecasts, and increase the ability of the grid to respond to emergency occurrences such as blackouts and brownouts. Further, the exchange of real-time prices and market data allows utility customers unprecedented control over their energy bills and promotes system-wide energy savings. It is for these reasons that AMI resources are poised to become the keystone of smart-grid technology.[184]

The backbone of a smart-grid system is the accurate, up-to-date, and predictable delivery of data between customer and utility company. AMI, unlike conventional metering systems, relies on fixed, digital network technologies. At the most basic level, AMI serves as a middleman between a consumer's energy consumption and the utility company that provides electricity, by reading household energy consumption at some predetermined, hourly or more frequent interval, and then storing and transmitting that data via a wired or wireless network to the provider. At higher levels, AMI technology incorporates two-way communication, transmitting real-time price and consumption data between the household and utility company and potentially acting as the center point for a Home Area Network, or HAN.

AMI technology should not be confused with automated meter reading (AMR) technology, which focuses on drive-by and walk-by meter-reading solutions and does not typically use fixed networks. It should be noted that AMR and AMI can be considered competing technologies; this is discussed in more detail in the Challenges section below.

Currently, AMI comprises about 4.7% of total U.S. electric meters,[185] with states in the Mid-Atlantic, Florida and Midwest (regions ERCOT, RFC and SPP) having the highest penetration rates (approximately 5-10%) and the remaining regions with lower-than-average reported rates (Figure M.12.2).

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[183] Federal Energy Regulatory Commission (FERC). August 2006. *Assessment of Demand Response and Advanced Metering.* Staff report. Docket Number: AD-06-2-000. Available at http://www.ferc.gov/legal/staff-reports/demand-response.pdf

[184] National Energy Technology Laboratory (NETL). 2008. *Advanced Metering Infrastructure.* Prepared for the U.S. Department of Energy Office of Energy Delivery and Energy Reliability. Accessed October 10, 2008, at http://www.netl.doe.gov/moderngrid/docs/AMI%20White%20paper%20final%20021108.pdf

[185] FERC 2008.

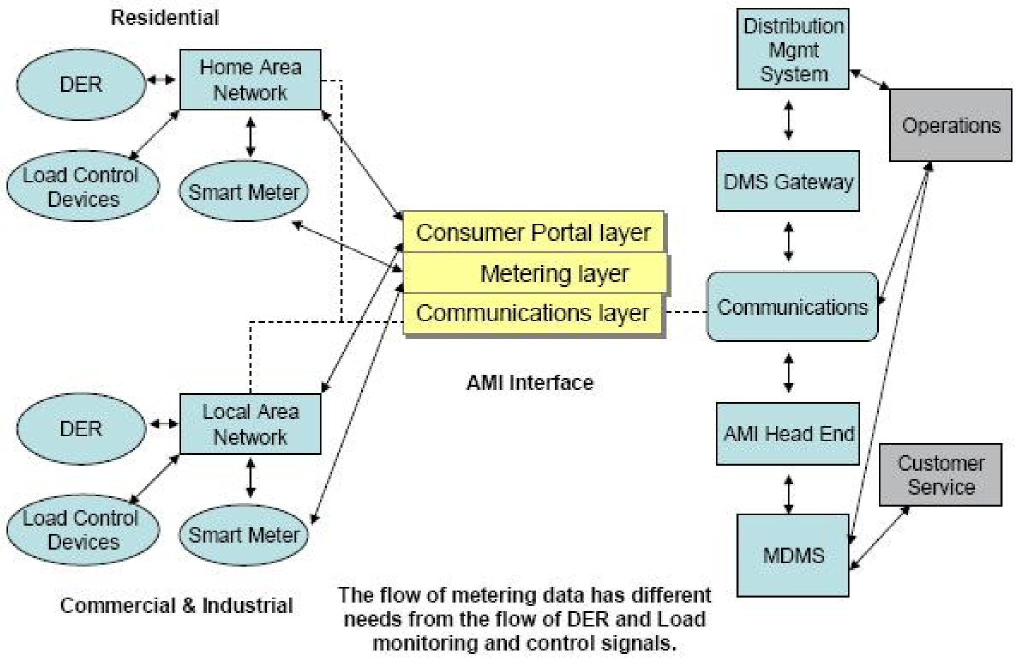

Figure M.12.1. Overview of AMI Interface[186]

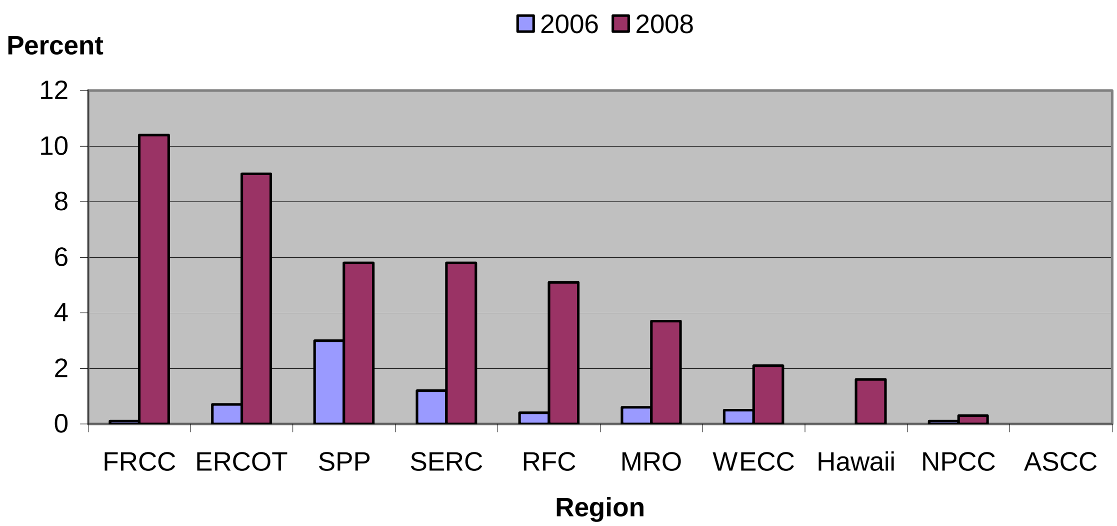

Figure M.12.2. Penetration of Advanced Metering by Region[187]

Table M.12.1 shows the states with the highest levels of AMI penetration. These numbers will be useful in establishing a baseline to track AMI penetration progress. FERC redefined penetration of AMI to mean that the meter was being used for advanced metering purposes. Thus, the percent penetration by region and state will have changed from the original FERC 2006 survey.

[186]NETL 2008.
[187]FERC 2008.

Table M.12.1. States with the Highest Penetration of Advanced Metering[188]

State	2006	2008
	Percent	
Pennsylvania	0.3	23.9
Idaho	3.9	13.8
Arkansas	5.0	11.3
North Dakota	0.0	8.9
South Dakota	0.0	8.7
Oklahoma	3.0	8.6
Texas	0.3	8.0
Florida	0.1	8.0
Georgia	1.7	7.6
Missouri	0.3	6.6
Vermont	0.0	5.5

In addition to the definition given by the FERC, a number of additional functions are desired in AMI technology.[189] The following list is taken directly from the 2007 Assessment of Demand Response and Advanced Metering:

- Ability to provide time-stamped interval data for each customer, at least hourly, but often as short an interval as 15 or 30 minutes
- Option of remote disconnect/connect for some or all meters
- Ability to remotely upgrade meter firmware
- Ability to send messages to equipment in or around customer home to support demand response
- Positive notification of outage and restoration (promising both significant cost savings and customer service benefits)
- Capability to remotely read meters on-demand
- Voltage flagging capability if voltage is outside of range configurable by utility
- Voltage interval reading capability at same interval as meter readings
- Tamper flagging capability
- Memory to store specified number of days of readings on meters (anywhere from 7 to 45 days, depending on the utility)
- Support for some form of prepay metering
- Daily register reading of meters, often at midnight

[188]FERC 2007.
[189]Harper-Slaboszewicz P. 2007a. "Ameren Real Time Pricing: Access to Lower Energy Prices." *Issue Alert*, May 16, 2007. Utilipoint International, Inc. Accessed October 10, 2008, at http://www.utilipoint.com/issuealert/article.asp?id=2853 .

- Inclusion of data warehousing systems—seen as increasingly necessary to store large volumes of data gleaned from AMI and meter data management systems (MDM)
- Tight integration with MDM into overall operations management systems—with links to accounting, billing, reporting, outage management, and other operations systems
- Ability to extend AMI and smart grids to multiple in-home appliances connected together as part of a home-area network (HAN). [190]

The remote connect/disconnect feature has received a great deal of attention from utility companies. The remote connect/disconnect feature will allow utility providers to disconnect a household's electricity service from a remote location. This allows utilities to inexpensively and quickly disconnect/reconnect a residence if its owners move or change utility providers, and could greatly assist utility companies as they contain and isolate outages. In fact, remote connect/disconnect has appeared in "almost every request for information or RFP issued by major investor owned utilities or large municipals in the last year." [191]

M.12.2.0 Description of the Metric and Measurable Elements

The following two measurements have been identified as important for understanding and quantifying advanced metering. Meters will have to meet the minimum qualifications set by the FERC to be counted in these measurements.

> *(Metric 12.a) Number of meters planned or installed*—tracking this number across states and regions will allow the United States to establish a baseline and a growth model for advanced meter penetration.

> *(Metric 12.b) Percentage of total demand served by advanced metering (AMI) customers*—knowing the percentage of the grid's load served by AMI technology will enable system operators to better manage load and deploy demand-response measures.

M.12.3.0 Deployment Trends and Projections

According to the metric, activity in advanced metering has been increasing rapidly, growing nearly 300% from 2005 to 2006. If these estimates continue, AMI penetration will double again by the end of 2008.[192] See Figure M.12.3.

If AMI deployments announced since 2006 proceed as planned, AMI penetration rates will skyrocket; more than 52 million new advanced meters are planned to be deployed by 2012. Today, however, penetration of advanced meters as a percent of total meters is very low at 4.7%.[193] According to interviews conducted for this report (see Annex B), by customer types, the percentage of installed meters that are currently "advanced" is:

- Residential – 1% averaged response; 0.2% when weighted by numbers of residential meters

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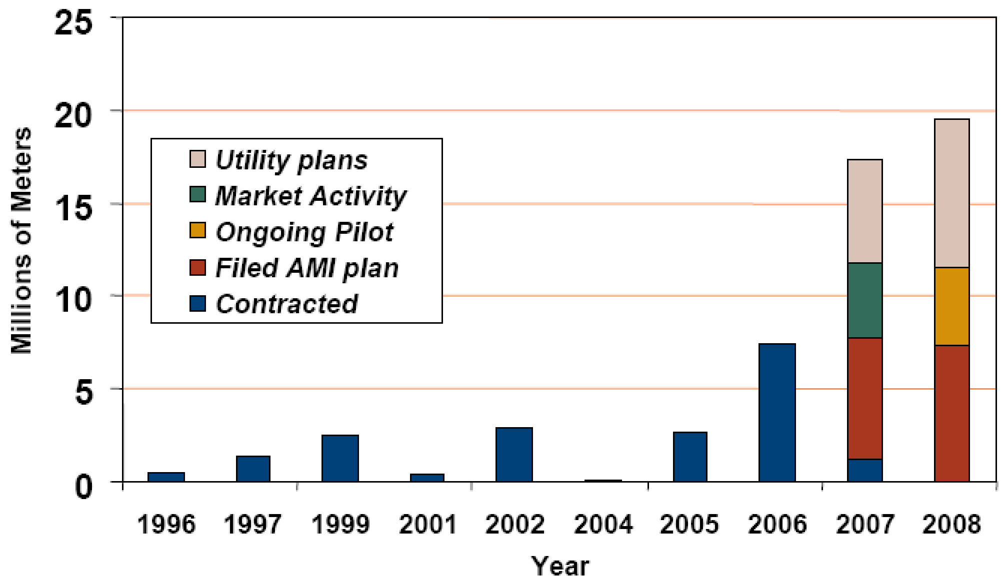
[190] FERC 2007.
[191] Harper-Slaboszewicz P. 2007b. "The Expanding Business Case for Remote Connect/Disconnect." *Issue Alert,* May 30, 2007. Utilipoint International, Inc. Accessed October 10, 2008, at http://www.utilipoint.com/issuealert/article.asp?id=2863
[192] FERC 2007.
[193] FERC 2008.

- Commercial – 2% averaged response; 1% when weighted by numbers of commercial meters
- Industrial – 43% averaged response; 18% when weighted by numbers of industrial meters
- Total – 2% averaged response; 3% when weighted by numbers of total meters



Notes:

- Contracted—The utility and the AMI vendor announced an agreement and/or signed a contract.
- Filed AMI plan—The investor-owned utility filed a plan to invest in AMI with its regulator.
- Ongoing Pilot—The utility is actively engaged in piloting AMI systems from one or more AMI vendors.
- Market Activity—The utility has issued RFPs for either AMI or an AMI consultant, or has hired an AMI consultant to prepare an RFP for AMI.
- Utility plans—The utility has publicly announced plans for investing in AMI.

Figure M.12.3. AMI Market Activity, Actual, and Projected[194]

In summary, concerning measurement 12.a, about 900 thousand advanced meters, or about 0.7% of all residential meters were in use in 2006; that grew to 6.7 million meters in 2008. The number of installed advanced meters has been projected to grow by another 52 million by 2012. Given that approximately one third of demand is residential, one could estimate that only about 4.4% of load is presently served by advanced metering. However, we recommend that good, independent data should be found to validate or refute this estimate of measurement 12.b.

M.12.3.1 Stakeholder Influences

Stakeholders in advanced metering include:

- Distribution service providers, to install and recover the investment in advanced meters.

[194]FERC 2007.

- Products and services suppliers including information technology (IT) and communications, to supply the appropriate technology for deployment and use of advanced meters.

- Local, state, and federal energy policymakers. Local regulators will be needed to ensure that distribution-service providers recover their investments in advanced meters. The California Energy Commission approved SDG&E's $572 million budget to install more than 2 million AMI approved gas and electric meters between 2008 and 2010.[195]

- The financial community. Numbers vary for how much it will cost to successfully deploy AMI technology but it will likely reach several billion dollars; for example, in 2007 PG&E requested an additional $624 million to bring their meters up-to-date with local AMI demands.[196]

M.12.3.2 Regional Influences

The majority of U.S. energy consumers are served by eight regional authorities. Each region operates under its own goals, contracts, and budgets. Energy prices and energy sources vary from state to state and in most cases even within the eight regions. These differences can lead to significantly different requirements as well as different cost and benefit estimations for AMI technology. Table M.12.2 contains excerpts from FERC's 2007 Assessment of Demand Response and Advanced Metering report and describes how key states have gone beyond EPAct 2005 requirements in developing legislation on advanced metering:

Table M.12.2. Various State Advanced-Metering Initiatives[197]

California	PG&E—received approval of its smart meter project application from the CPUC. SDG&E—received approval of its smart meter project following a settlement with the utility, the PUC's Division of Ratepayer Advocates, and advocacy group the Utility Consumers Action Network.[198] Southern California Edison—requested approval for its Phase II AMI Pre-Deployment Activities and Cost Recovery Mechanism is pending before the CPUC.[199]
Connecticut	The state of Connecticut passed a new demand response-advanced metering infrastructure (DR-AMI) bill requiring utilities in the state to install new "smart" meters and associated technologies capable of measuring real-time prices in support of mandatory TOU pricing. Deploy AMI by January 1, 2009.[200]

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[195]Chavez M. 2008. *California's Advanced Metering Infrastructure Initiatives*. Energy Division Report, California Public Utility Commission, presented January 22, 2008 at the State Clean Energy-Environment Technical Forum. Accessed October 13, 2008, at http://keystone.org/Public_Policy/2007_8DOCS_CLEANENERGY/01_22_08%20CAAMI_Initiatives_Chavez.pdf

[196]Chavez 2008.

[197]FERC 2007.

[198]Press release. April 12, 2007. *SDG&E's "Smart Meter" Program Receives Final State Approval*. Accessed November 14, 2008 at http://public.sempra.com/newsreleases/viewpr.cfm?PR_ID=2150&Co_Short_Nm=SDGE.

[199]Southern California Edison *Application for Approval of Advanced Metering Infrastructure Pre-Deployment Activities and Cost RecoveryMechanism,* Available at http://www.sce.com/NR/rdonlyres/5F9E844C-9958-431D-B822-A6B72F544174/0/01_2007_AMI_Phase_II_legal_Insert.pdf

[200]Connecticut Light & Power (CL&P). 2007. "Advanced Metering Infrastructure Plan." Compliance Filing in Connecticut Docket No. 05-10-03RE01. Accessed October 13, 2008, at http://www.dpuc.state.ct.us/dockcurr.nsf/f7de85eded62752a8525655d005653b8/397da67f9cb6efb8852574160048dbd3/$FILE/05-10-03RE01%20CL&P%20Compliance.PA%2007-242.sec%2098.coverletter.7.2.07.pdf. See also Sections 13(a) and 13(c) of Connecticut's Public Act 05-01, *An Act Concerning Energy Independence* ("EIA").

Table M.12.2. (contd)

Connecticut (contd)	Connecticut Light & Power—submitted its AMI plan, which is pending before the Department of Public Utility Control (DPUC).[201]
District of Columbia	The DC Public Service Commission approved a pilot program (PowerCentsDC), which allows residential customers involved with the pilot to test three different pricing schedules.[202] The program is said to be a first of its kind in the electric industry.[203]
New York	New York State Public Service Commission (NYSPSC)—issued an order requiring electric utilities to conduct AMI cost-benefit studies and file comprehensive plans for development and deployment of advanced metering systems.[204] Con Edison and Energy East (Rochester Gas & Electric (RG&E) and New York State Electric & Gas (NYSEG))—have filed their plans.[205] In its plan, Energy East suggested that with NYSPSC approval, RG&E and NYSEG could begin meter installation as early as 2008. Con Edison–filed a proposal for an electric rate increase that included $340 million to install AMI and AMR (May 4, 2007).[206]
Texas	State of Texas—passed legislation (House Bill 2129) in 2006 allowing utilities to use surcharges to fund advanced meters.[207] PUC of Texas—issued a proposed rulemaking that lists minimum functionality criteria utilities would be required to meet with their advanced-metering deployments. The Texas rulemaking added several advanced capabilities to the minimum functionality criteria, such as two-way communications, capability to provide timely customer usage data to retail electric providers, capability for customers to receive pricing signals from their retail electricity providers or a designated customer agent, and the ability to upgrade capabilities as technology advances.[208] The proposed rulemaking also states that an electric utility "shall not deploy an AMS (advanced metering system) that has not been successfully installed previously with at least 500 advanced elsewhere in the world, except for pilot programs." On September 29, 2006, the PUC of Texas reported to the Texas legislature its finding that there are no barriers to AMI in Texas.[209]
Vermont	Vermont Public Service Board—opened a docket requiring both statewide AMI and utility-by-utility AMI cost-benefit studies.[210]

[201]CL&P compliance filing.

[202]Formal Case No. 1002, In The Matter Of The Joint Application Of Pepco And The New RC, Inc. For Authorization And Approval Of Merger Transaction. DC PSC Order No. 14166 (January 12, 2007). Accessed November 24, 2008 at http://dcpsc.org/edocket/docketsheets_pdf_FS.asp?caseno=FC1002&docketno=223&flag=C&show_result=Y

[203]*Transmission & Distribution World***.** May 9, 2007. **"**Pilot Program to Help Washington DC Customers Manage Electricity Bills." Penton Media, Inc. Accessed November 14, 2008 at http://tdworld.com/info_systems/highlights/sensus-smart-metering-contract/index.html

[204]Con Edison compliance filing, March 28, 2007.

[205]*Advanced Metering Infrastructure Overview and Plan.* February 1, 2007. Rochester Gas and Electric Corporation New York State Electric and Gas Company. Accessed November 14, 2008 at http://www.dps.state.ny.us/NYSEG_RGE_AMI_Filing.pdf

[206]Con Edison of New York's Electric Rate Case Filing - May 4, 2007. Accessed November 24, 2008 at http://investor.conedison.com/phoenix.zhtml?c=61493&p=irol-newsArticle&ID=995985&highlight=.

[207]PUC of Texas, Project No. 31418, *Rulemaking Related to Advanced Metering, Proposal for Publication of Amendments to §§25.121, 25.123, 25.311, and 25.346 and New §25.130 as approved at the October 26, 2006 Open Meeting*. Accessed November 24, 2008 at http://www.puc.state.tx.us/rules/rulemake/31418/31418pub.pdf

[208]PUC of Texas. 2006.

[209]PUC of Texas, January 2007. *Report to the 80th Texas Legislature on "Scope of Competition in Electric Markets in Texas."* Accessed November 14, 2008 at http://speakuptexas.com/electric/reports/scope/2007/2007scope_elec.pdf

[210]Vermont Public Service Board, Smart Metering RFP. Accessed November 14, 2008 at http://publicservice.vermont.gov/energy-efficiency/SmartMeterRFP.pdf

M.12.4.0 Challenges

AMI manufactures and designers face a myriad of demands from utility companies and the consumers they represent. Subjects such as weatherproofing, maintenance schedules, and memory storage all need to be addressed in addition to the development of and adherence to national and state standards for design, communication, and more. These challenges are discussed below.

M.12.4.1 Technical Challenges

There are a variety of technical considerations involving advanced meters. Although a uniform understanding of minimum qualifications for AMI technology exists, many utilities will find any number of additional qualifications and functions necessary to effectively serve their clients. As each utility or region has different challenges, including additional "minimum" features or "standard features," AMI systems may prove to be redundant, less cost effective, or even useless in some cases. Additionally, there may be different opinions on what qualifies as a specific function between regions. For example, PG&E's definition of "tamper flagging capability" may be significantly different from Connecticut Light & Power's. Other considerations such as battery backup, network structure, communication protocols and encryption also pose technical challenges.

M.12.4.2 Business and Financial Challenges

Advanced metering systems do not enter an empty market. Drive- or walk-by meters (AMR) have existed for some time and are "possibly discouraging the installation of the more demand response-friendly AMI."[211] Although recent data suggest that more AMR meters are being shipped than AMI meters, once utility companies became aware of the increasing benefits of AMI technology they have announced plans to replace all non-AMI-compatible meters, including previously installed AMR meters. Connecticut Light & Power is one such company.[212] Within 5 years, sales of AMI meters are expected to outpace sales of AMR meter and both are expected to continue a combined yearly growth of about 20% over the next 5 or 6 years.[213] Implementing Smart Meters has been forecast to cost between $19 and $27 billion.[214] These costs will increase due to dissimilar regional requirements for AMI system features. With different regions making different demands on their AMI systems, vendors cannot respond with a homogeneous product. Additionally, after deployment, AMI devices may find themselves subject to rapid obsolescence, or in need of frequent software and/or hardware updates. Another challenge facing AMI-related firms is that many manufactures/developers are attempting to bundle home area networks (HAN) into AMI technology. Thus, AMIs will act as a residential communication gateway to connect smart meters with 'smart' electronic devices.[215] While this technology could potentially revolutionize how consumers interact with their appliances, (allowing device control via the internet, for example), it is not clear how service providers, vendors, and customers cooperate to overcome the development, installation, and security challenges that come with such technology.

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[211] FERC 2007.
[212] CL&P Compliance Filing.
[213] FERC 2007.
[214] Kuhn TR. 2008. *Legislative Proposals to Reduce Greenhouse Gas Emissions: An Overview*. Testimony before the United States House of Representatives Subcommittee on Energy and Air Quality, June 19, 2008. Accessed September 4, 2008, at http://www.eei.org/about_EEI/advocacy_activities/Congress/080619KuhnHouseGreenhouseGases.pdf
[215] NETL 2008.

In addition, business-case analysis still needs to be undertaken to determine the benefits/costs of implementing AMI. These analyses should include impacts to employment, amounts of stranded equipment, and whether the manufacture and installation rates are sustainable. Customers and their representatives need to see sufficient benefits for the costs.

M.12.5.0 Metric Recommendations

Good, reportable data have not yet been found for measurement 12.b concerning the fraction of load served by AMI. We recommend that further research be conducted to locate or learn this value. Instructions for Form 861 indicate that the EIA will collect information on MWh of energy served through AMI, but isn't collecting the amount of load that is being served by AMI.[216]

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[216] U.S. Department of Energy. 2007. *Form EIA-861 (2007) Instructions for Form 861 Annual Electric Power Industry Report.* Energy Information Administration (EIA). http://www.eia.doe.gov/cneaf/electricity/forms/eia861/eia861instr.doc. Date accessed: 10/29/2008.

Metric #13: Advanced Measurement Systems

M.13.1.0 Introduction and Background

A Wide Area Measurement System (WAMS) describes an advanced-technology infrastructure that is designed to develop and integrate measurement-based information into the grid-management process. The overall infrastructure encompasses measurement facilities, operational support, and data utilization. WAMS measurement facilities that communicate data sampled typically 30 times per second or more are designed to augment those of conventional SCADA over which measurements are "refreshed" at a much slower rate, e.g., once every 4 seconds. Currently used as a complementary system, a WAMS is expressly designed to enhance the operator's real-time "situational awareness," which is necessary for safe and reliable grid operation.[217] In the future, WAMS technologies are expected to be incrementally incorporated into the actual control system of the grid.[218]

WAMS technologies incorporate highly accurate time-synchronized measurements. For example, one type of device known as the phasor measurement unit (PMU) utilizes accurate timing signals transmitted by Global Positioning System (GPS) satellites to determine relative phase angle differences between different locations in the grid. An additional benefit of this instrument class is that the data can be networked to form a wide area view of the overall power system operation.

WAMS has evolved over the past two decades to provide the following functions:[219]

- Real-time observation of system performance
- Early detection of system problems
- Real-time determination of transmission capacities
- Analysis of system behavior, especially major disturbances
- Special tests and measurements, for purposes such as
  - Special investigation of system dynamic performance
  - Validation and refinement of planning models
  - Commissioning or re-certification of major control systems
  - Calibration and refinement of measurement facilities
- Refinement of planning, operation, and control processes essential to best use of transmission assets.

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[217] Hauer JF and JG DeSteese. 2007. *Descriptive Model of a Generic WAMS.* PNNL-17138, Pacific Northwest National Laboratory, Richland, Washington. Accessed October 16, 2008, at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17138.pdf

[218] Hadley MD, JB McBride, TW Edgar, LR O'Neil, and JD Johnson. 2007. *Securing Wide Area Measurement Systems*. PNNL 17116, Pacific Northwest National Laboratory, Richland, Washington.

[219] Hauer JF, WA Mittelstadt, KE Martin, JW Burns, and H Lee. 2006. *Best Practices to Improve Power System Dynamic Performance and Reduce Risk of Cascading Blackouts: Monitoring of System Dynamic Performance*. IEEE Power Engineering Society Task Force on Best Practices to Minimize Blackout Risk. IEEE Power Engineering Society, New York.

Information collected from WAMS is often used to support post-mortem investigations of large-scale blackouts. The disturbance-monitoring function is characterized by large signals and relatively short event records. In addition, precursors to the actual disturbance are often only found in WAMS data, that uniquely provides long records containing small signals with high bandwidth. With complex processing (such as correlation analysis of multiple records) and direct motioning of phase voltages and currents, early warnings of emerging trouble can be found.[220]

IEDs, such as digital fault recorders (DFR) and microprocessor-based protective relays, provide another valuable source of data for establishing an accurate and detailed sequence of events, particularly during the cascading phase of the blackout when events are occurring rapidly.[221]

Digital fault recorders and protective relays are high-speed instruments installed in substations that are designed to measure faults, and in the case of protective relays, act on that information to trip circuit breakers to protect assets from becoming damaged. By capturing the waveform of a fault, detailed information regarding the nature and location of the fault can be calculated, and the proper response of the protective relays and circuit breakers can be confirmed. These devices gather high-speed data and are (usually) synchronized to an accurate time standard. When a large-scale system disturbance occurs, they are an invaluable source of data that is used to support the investigation process, particularly in establishing the timing of events, or confirming the cause of the relay action and breaker trip.

The Common Format for Transient Data Exchange (COMTRADE), IEEE Standard C37.111, is a widely used example of a digital data format for oscillography. Most classes of IEDs that capture high-speed data can export their data in the COMTRADE format. However, the investigation team's access to this data can often be cumbersome. Therefore, it is preferable to consider these issues proactively so that delays during the investigation process can be minimized.

The goal set by DOE[222] in its Report to Congress on the 5-year plan for electric power distribution and transmission was for the grid planners and operators to have the techniques, tools, and technologies needed to operate a smart, reliable grid by 2014. In 2006, real-time data collection was limited to about 100 sensors of various types. The report set an objective of another 100 transmission level sensors by 2009 and deployment of at least 100 distribution-level sensors by 2012.

M.13.2.0 Description of Metric and Measurable Elements

The measurable elements for this metric include:

(Metric 13) the total number of advanced measurement devices: the total number of measurement devices that are networked and are providing useful information at the transmission and distribution levels.

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[220]Hauer et al. 2006.

[221]Dagle JE. 2006. "Postmortem Analysis of Power Grid Blackouts - The Role of Measurement Systems." *IEEE Power & Energy Magazine* 4(5):30-35. Available at http://www.ieee.org/organizations/pes/public/2006/sep/index.html

[222]U.S. Department of Energy (DOE). August 2006. *Five-Year Program Plan for Fiscal Years 2008 to 2012 for Electric Transmission and Distribution Programs. Report to Congress Pursuant to Section 925 of Energy Policy Act of 2005*. DOE, Washington, D.C. Accessed October 16, 2008, at: http://www.oe.energy.gov/DocumentsandMedia/Section_925_Final.pdf

M.13.3.0 Deployment Trends and Projections

There are approximately 165 PMUs installed in late 2008. In the eastern interconnection, there are 104 PMUs with 89 networked and 61 PMUs in the western interconnection.[223] One trade source indicates there were 150 PMUs installed in early 2008 within the eastern and western interconnections[224] up from the 100 PMUs indicated in 2006.[225] Installed and networked PMUs have been increasing as 35 PMUs were installed by June 2006 in the Eastern Interconnection while only 20 PMUs were installed and networked as of January 2006.[226] A study completed by Northeastern University[227] indicated that between 721 and 1300 PMUs would be necessary to address a complete set of applications envisioned for the Entergy network. However, fewer PMUs can provide sufficient information for wide-area visibility for situational awareness of the grid. A NERC technical committee report indicated that at least 500 phasor measurement units would be required to adequately monitor the grid.[228]

Interviews concerning the current prevalence of phasor measurement units and digital fault recorders were conducted for this report (see Annex B). The interviews indicated that 14 of the 21 companies surveyed had altogether 50-75 phasor measurement units, and 10 of the companies had digital fault recorders, 2800-3200 units, altogether. The remaining companies did not report possessing either item. The companies surveyed represent between 200 and 250 GW of substation capacity and between 170 and 190 GW of peak load.

M.13.3.1 Associated Stakeholders

Advanced measurement systems primarily affect transmission providers, distribution service providers and end-users, but they will also reliability coordinators and products and services suppliers. In more detail, they are:

- Transmission providers: need to understand the business case for deploying advanced measurement technology and properly quantify the benefits of this technology to enhance the reliability of the power system.
- Reliability coordinators and the North American Electric Reliability Corporation (NERC) have roles in ensuring grid reliability. They will also need to understand the business case for deployment of the advanced measurement systems.

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[223]Dagle, JE. September 20, 2008. Personal Communications (email) stating the number of PMUs.
[224]Galvan F, L Beard, J Minnicucci, and P Overholt. 2008. "Phasors Monitor Grid Conditions." *Transmission and Distribution World*. Accessed October 16, 2008, at http://tdworld.com/overhead_transmission/phasors_monitor_grid_conditions/.
[225]DOE 2006. *Five-Year Program Plan for Fiscal Years 2008 to 2012 for Electric Transmission and Distribution Programs.*
[226]Widergren SE, Z Huang, JE Dagle. January, 2007. "Electric System-wide Measurements: North American Directions." In *Proceedings of the 40th Hawaii International Conference on System Sciences (HICSS 40), January 3-6, 2007*. Accessed November 24, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=4076613&isnumber=4076362
[227]Galvan F, L Beard, J Minnicucci, and P Overholt. 2008. "Phasors Monitor Grid Conditions." *Transmission and Distribution World*. Accessed October 16, 2008, at http://tdworld.com/overhead_transmission/phasors_monitor_grid_conditions/.
[228]North American Energy Reliability Council (NERC). May 2007. "Technology Committee Minutes May 1, 2007." Accessed September 4, 2008 at: http://www.nerc.com/docs/bot/bottc/TC_0507m_Draft.pdf.

- Distribution service providers will benefit from better customer relations associated with the enhanced grid reliability.

- End users (residential, commercial and industrial) have a stake in anything that could affect power system reliability.

- Products and services suppliers have a role in helping to educate the industry about the need for advanced systems and continued development of the technology.

- Local, state and federal energy policymakers all have a stake in ensuring the reliability of the grid, which has been a significant force behind the U.S. economic engine.

M.13.3.2 Regional Influences

While the basic technology is being deployed throughout the world, there are key regional differences that drive the applications that are sought from advanced measurement technologies. Measuring interregional electromechanical oscillations fueled the early development of WAMS in the western interconnection. First appearing in the grid in the early 1970s when the Northwest region was connected to California through the Pacific Intertie transmission projects, these oscillations were a continuing source of reliability concern and factored prominently in the August 10, 1996 blackout.

Driven by stability considerations, and in an earlier regulatory environment, utilities within the western interconnection made significant progress in the development of monitoring facilities for examining system behavior. This development is a collective response to their shared needs for measurement-based information about system characteristics, model fidelity, and operational performance.[229,230]

Data from WAMS was instrumental in the investigation of that blackout and continues to be a source of knowledge and insight into the western interconnection dynamic behavior. Spiegel et al.[231] indicated there are 54 PMUs integrated across the western interconnection.

Data from PMUs were also instrumental while investigating the August 14, 2003 blackout that affected large portions of the Northeastern United States and Canada. More importantly, the blackout investigation report cited lack of situational awareness as one of the root causes that contributed to the blackout.

The North American SynchroPhasor Initiative (NASPI) is a joint DOE and NERC program to help facilitate the deployment of time-synchronized measurements, including particularly PMUs, throughout North America. NASPI embodies a vision where value is delivered within the operations and planning

[229]Western States Coordinating Council (WSCC). 1990. *Evaluation of Low Frequency System Response: Study Results and Recommendations*. Report of the WSCC 0.7 Hz Oscillation Ad Hoc Work Group to the WSCC Technical Studies Subcommittee, September 1990.
[230]Hauer JF and JR Hunt (in association with the WSCC System Oscillations Work Groups). 1996. *Extending the Realism of Planning Models for the Western North America Power System*. V Symposium of Specialists in Electric Operational and Expansion Planning (SEPOPE), May 19-24, 1996, Recife, PE, Brazil.
[231]Spiegel L, S Lee, and M Deming. 2007. *Review of Research Projects for Managing Electric Transmission Uncertainty*. Public Interest Energy Research (PIER) TRP Policy Advisory Committee Meeting and California Energy Commission Staff Workshop.

environment using new interregional information and measurement systems. The effort is closely coordinated with industry.[232,233]

Figure M.13.1 shows, as of 2007, the existing and planned PMU deployment locations in North America. There are many PMUs installed that are not networked across organizations not shown on the map, with many more projected in the future.

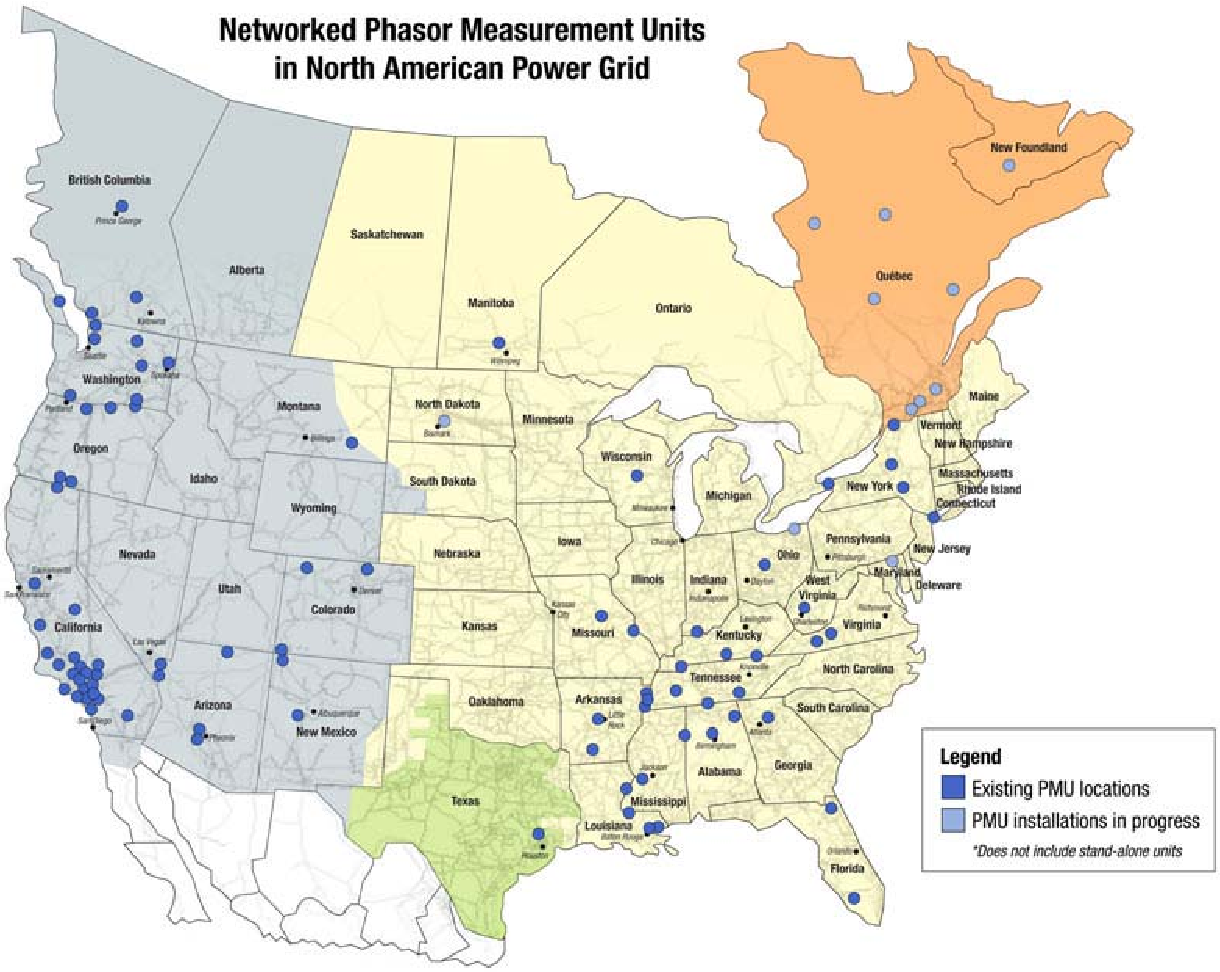

Figure M.13.1. Networked Phasor Measurement Units in the North American Power Grid[234]

[232] Dagle JF. 2008. "North American SynchroPhasor Initiative." *Proceedings of the 41st Hawaii International Conference on System Sciences - 2008*. Accessed November 24, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=4438868&isnumber=4438696

[233] NASPI 2008. *North American SynchroPhasor Initiative*. Accessed November 24, 2008 at http://www.naspi.org/. Last Updated September 2008.

[234] (EIOC) Electricity Infrastructure Operations Center. *North American SynchroPhasor Initiative*. U.S. Department of Energy and Pacific Northwest National Laboratory. Accessed November 24,2008 at http://eioc.pnl.gov/research/synchrophasor.stm / . Last updated July 2008.

M.13.4.0 Challenges to Deployment

The primary challenge to deployment is capturing the business case that advanced measurement technologies provide sufficient benefits beyond more traditional measurement technologies to justify their incremental cost. Primary challenges to deployment include the measurement equipment, networking infrastructure, interoperability and data sharing issues, and applications such as improved visualization tools and other decision-support systems.

As it relates to smart-grid applications, there will undoubtedly be much more raw data available from the smart-grid equipment, but integrating and managing this information will be a significant challenge.

M.13.4.1 Technical Challenges

Primary technical challenges to deployment include the measurement equipment and the communication and networking infrastructure. Another technical challenge is interoperability and standardization. A third primary challenge is improved applications, such as visualization tools that can help operators cope with the increased flow of information associated with the installation of advanced measurement technology.[235,236,237]

Another issue is the degree to which actual phasor data will be shared among utilities and with others. Analysis is needed to identify potential smart-grid applications that rely on phasor data and to assess whether existing coverage is sufficient for the application. There is still a need to assess the usefulness of small signal-stability algorithms and expand them to include mode shapes and determine remedial actions associated with the signals.[238] Weekes and Walker[239] also point out seven different types of organizations that are required to install PMUs: information technology, plant engineering, protection maintenance, protection technicians, communication engineering, commissioning, and transmission services. These all need to be coordinated effectively by management for successful and efficient installation.

Additional work on the measurement technologies themselves is warranted. According to Weekes and Walker,[240] different PMUs give different results for the same measurement input.

M.13.4.2 Business and Financial Challenges

A 2006 survey indicated that nearly 59 percent of utilities do not use and have no plans to use WAMS

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[235] DOE 2006. *Five-Year Program Plan for Fiscal Years 2008 to 2012 for Electric Transmission and Distribution Programs.*

[236] Dagle JE, 2008. "North American SynchroPhasor Initiative." 41st annual Hawaii International Conference on System Sciences.

[237] Weekes M.A and K Walker. 2007. "PMU Challenges and Performance Issues." 2007 IEEE Power Engineering Society General Meeting. Institute of Electrical and Electronics Engineers, Piscataway, New York. Accessed October 16, 2008, at http://ieeexplore.ieee.org/iel5/4275198/4275199/04275770.pdf?tp=&isnumber=&arnumber=4275770.

[238] Spiegel L, S Lee, and M Deming. 2007. "Review of Research Projects for Managing Electric Transmission Uncertainty." Public Interest Energy Research (PIER) TRP Policy Advisory Committee Meeting and California Energy Commission Staff Workshop.

[239] Weekes and Walker 2007.

[240] Weekes and Walker 2007.

as opposed to 67 percent respondents in a 2004 survey.[241] Although the trend is an improvement in terms of utilities that find advanced measurement systems beneficial, it indicates that a large percentage of utilities do not see the benefits outweighing the costs associated with the purchase and installation of advanced sensors.

The August 14, 2003 blackout underscored the need for more reliable situational awareness. More than 50 million people were affected by the blackout with estimated economic losses in the United States were estimated at $4 to $10 billion while 61,800 MW of capacity was lost.[242]

M.13.5.0 Metric Recommendations

The advanced measurement systems metric emphasizes wide area measurements; however, future reports should consider distribution sensor systems aimed at such problems as power quality. The number of installed and networked PMUs should be regularly collected and published each year. Currently the information was assembled through questions to people involved in the North American Synchro-Phasor Initiative.

There are two potential metrics that could be helpful in describing progress for Advanced System Measurement. The two metrics are,

1. *(Metric 13.b) the percentage of substations possessing advanced measurement technology*: the percentage of substations in the U.S. of various voltage and power ratings possessing advanced measurement technology that are networked and are providing useful information;.

2. *(Metric 13.c) the number of applications supported by these various measurement technologies:* the number of applications being supported by these various measurement technologies to support either enhanced system reliability or effective operations.

Currently no data are available for the two metrics: the percentage of substations possessing advanced measurement technology and the applications supported by these various measurement technologies.

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[241]Newton CW. 2007. "Highlights from the North American Study of Electric Power Utilities Protection and Control Management and Staff." *Electric Energy T&D Magazine* 3(11):16-23. Accessed October 16, 2008, at http://www.electricenergyonline.com/article.asp?m=9&mag=43&article=319.

[242]U.S. Department of Energy (DOE) and Natural Resources Canada. April 2004. "U.S.-Canada Power System Outage Task Force: *Final Report on the August 14th Blackout in the United States and Canada."* Accessed 11/21/2008 at https://reports.energy.gov/

Metric #14: Capacity Factors

M.14.1.0 Introduction and Background

A *capacity factor* is the fraction of energy that is generated by or delivered through a piece of power system equipment during an interval, compared to the amount of energy that could have been generated or delivered had the equipment operated at its design or nameplate capacity. In principle, a capacity factor is readily understood and measured for many types of transmission and distribution equipment, including power generators, transformers, and transmission and distribution lines. Intuitively understood, a capacity factor of zero means that equipment was unused during an interval; a capacity factor of 100% means that the equipment was, on average, used at its rated capacity throughout an interval; and a capacity factor over 100% means that the equipment was overloaded, often an unsustainable or even dangerous condition. A capacity factor may therefore be convenient and useful as an indicator and should serve as a metric of the health and evolution of the smart grid.

Consider some of the traditional approaches to managing capacity factor: if a transmission circuit becomes inadequate, a new circuit is built, or the circuit is reconductored to increase the corridor's design capacity. If electrical load grows, new centralized generating plants are constructed. If you install an on-demand electric water heater in your home, you and your utility must consider whether your home's distribution transformer might require replacement. Indeed, these approaches are effective at managing capacity factors and operational margins.

One thesis of a smart grid is that the power system should be able to defer or eliminate the installation of infrastructure, thus achieving more energy production and transmission using existing equipment. Intelligent controllers might permit us to operate safely close to operational boundaries of installed grid infrastructure. The smart grid should recognize and mitigate stressful conditions on the grid, reacting dynamically to conditions that could overload the grid's infrastructure. Efficient loads can, of course, be supplied more easily than can inefficient ones. These examples are several smart-grid development opportunities that would directly affect, and could be monitored, at least in aggregate, by capacity factors.

The degree with which the nation has recently embraced renewable energy offers another good example with respect to this metric. Renewable generation resources like wind are intermittent. Inclusion of an increasing number of wind generators into a capacity-factor metric will reduce the apparent, aggregate capacity factor of the nation's electricity generators. Because renewable resources are often located far from population centers that would use their energy, growing renewable generation resources with varying output could create fluctuations in available transmission capacity factors as the variation in transmission flows increases either upward or downward (due to fluctuations in generation schedules). Successful implementation of distributed-generation resources, perhaps including renewable ones, near electric loads that they serve could, in principle, reduce the need to transfer much energy over distances. Distributed storage resources could achieve a similar effect. Again, one can see how this metric might be useful for surveying and discussing the effects of renewable resource penetration, even though the metric trends might be simultaneously influenced in both upward and downward directions by attributes of renewable resources.

Consumer trends will also affect capacity factor. Our nation's hunger for plug-load electronics and the possibility that our consumption of fossil fuels will become displaced by plug-in hybrid electric vehicles both present new challenges—and perhaps opportunities—for the management of capacity factors within our distribution systems.

A smart grid should better use the available capacity of its infrastructure by flattening load profiles. Load profiles that have large diurnal and seasonal peaks stress grid infrastructure and are inefficient with respect to both cost and energy. Conduction losses increase with the square of conducted electrical current. Inefficient, polluting generators are dispatched to meet only the occasional, peak demand. Therefore, not only average capacity factor, but also peak capacity factor should be measured and reported. Of interest are measurements of both yearly peaks and averaged daily peaks.

M.14.2.0 Description of the Metric and Measurable Elements

This section defines specific measurements that will represent capacity factors across the power grid's generation, transmission, and distribution systems, as well as across major types of power-grid equipment, including generators, conductors, and transformers. Three measurements that pair generation with generators, transmission with conductors, and the distribution system with transformers are proposed. Each pairing invites and defines both average and peak capacity-factor measurements.

> *(Metric 14.a) Yearly average and peak generation capacity factor (%)*—the yearly average capacity factor of the nation's entire generator population should be estimated (see Equation 14.a).

This metric requires that the total national electricity generation and the total electricity generation nameplate or design capability of the nation's generators should be accurately estimated each time this metric is to be updated. With minor modification of this calculation, one can estimate the yearly or average daily peak generation capacity factor answering, "How close did the nation come last year to exceeding its generation capacity?"

$$CF_{\text{Generation}}(\%) = \frac{\sum_{\textit{All Generators}} \sum_{\text{Year}} \text{Generated Energy (MWh)}}{8760\,(\text{hours}) * \sum_{\textit{All Generators}} \textit{Generator Power Rating}\,(MW)} * 100\,(\%) \qquad (14.a)$$

> *(Metric 14.b) Yearly average and average peak capacity factor for a typical mile of transmission line (%-mile per mile)*: capacity factor of the nation's transmission lines should be estimated, the result being weighted to account for transmission line distances (See Equations 14.b1 and 14.b2).

A minor modification of this measurement can be performed to also provide the yearly or daily average *peak* transmission capacity factor on a mile of our nation's transmission lines during the year.

$$CF_{\text{Trans. Line}}(\%) = \frac{\sum_{\text{year}} \text{Transmitted Energy (MWh)}}{8760\,(\text{hours}) * \sum \text{Line Power Rating (MW)}} * 100\,(\%) \qquad (14.b1)$$

$$CF_{\text{Per Mile Trans. Line}}(\%) = \frac{\sum_{\text{All Lines}} \text{Line Distance (miles)} * CF_{\text{Trans. Line}}(\%)}{\sum_{\text{All Lines}} \text{Line Distance (miles)}} \qquad (14.b2)$$

(Metric 14.c) Yearly average and average peak distribution transformer capacity factor (%): estimate of the average capacity factor of the nation's distribution transformers over the year (see Equation 14.c).

This calculation may be modified to further define the yearly or average daily *peak* distribution transformer capacity factor across all distribution transformers.

$$CF_{\text{Dist. Xfmr}}(\%) = \frac{\sum_{\text{All Xfmrs.}} \sum_{\text{year}} \text{Xfmr.Energy(MWh)}}{8760\,(\text{hours}) * \sum_{\text{All Xfmrs.}} \text{Xfmr.Ratings(MW)}} * 100(\%) \qquad (14.c)$$

M.14.3.0 Deployment Trends and Projections

Useful data for metric measurement 14.a were found concerning our nation's generation adequacy. Most informative were the data collected and forecast by NERC.[243] These list peak summer demand and summer generation capacity, peak winter demand and winter generation capacity, and yearly energy demand for each major NERC region. Published data included measurements from 1989 through 2006 and projected estimates through 2016. Table M.14.1 summarizes these data and the resulting Metric 14.a capacity factor measurements for two years: 2006, the most recent year for which measured data is provided, and 2008, the present year, for which only projected data are provided. On average, a little less than half of the nation's generation capacity is now used, but less than 20% of the nation's total generation capacity remains unused during summer peaks. Smart grid techniques may be able to increase asset utilization, thus increasing overall capacity factors.

Table M.14.1. Measured and Projected Peak Demands and Generation Capacities for Recent Years in the U.S.[244] and Calculated Capacity Factors

	2006 Measured	2008 Projected
Summer peak demand (MW)	789,475	801,209
Summer generation capacity (MW)	954,697	991,402
Capacity factor 14.a, peak summer (%)	82.69	80.82
Winter peak demand (MW)	640,981	663,105
Winter generation capacity (MW)	983,371	1,018,124
Capacity factor 14.a, peak winter (%)	65.18	65.13
Yearly energy consumed by load (GWhr)	3,911,914	4,089,327
Capacity factor 14.a, average (%)[(a)]	46.08	46.46

(a)The average of the NERC (2006) summer and winter capacities was used for this calculation.

Some trends can be observed in these data in Figure M.14.1, which points out the maximum and minimum capacity factors and years for each of the three data sets. According to these NERC data, the U.S. crept closer to its generation limits for at least the ten years preceding 1998-2000, but it sharply reversed that trend during the next 5 years and returned to more conservative generation capacity factors. Relatively constant generation capacity factors are predicted for the next 8 years.

[243]North American Electric Reliability Corporation (NERC). 2007. *Electricity Supply & Demand (ES&D): Frequently Requested Reports. 2007 Reports (with 2006 actuals)*. Accessed October 12, 2008 at http://www.nerc.com/page.php?cid=4|38|41.

[244] NERC 2007.

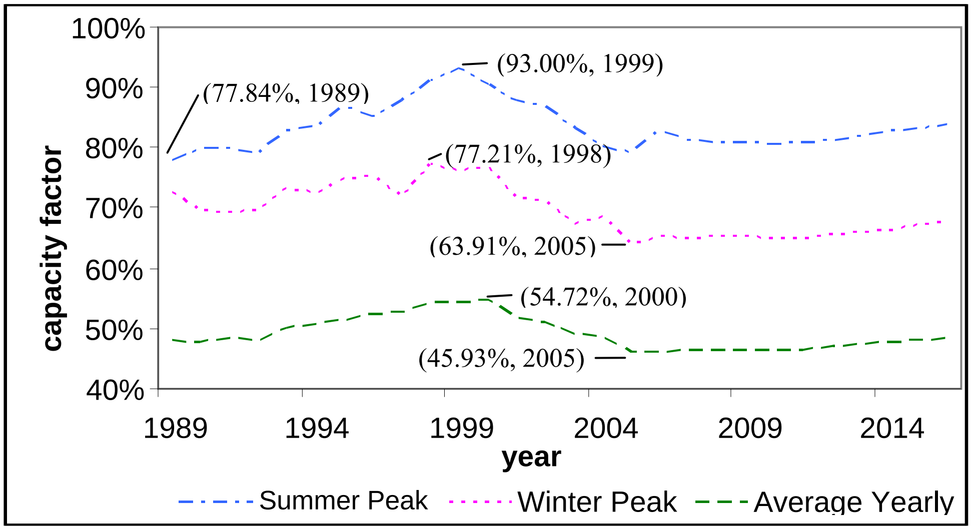

Figure M.14.1. Measured and Predicted Peak Summer, Peak Winter, and Yearly Average Generation Capacity Factors in the U.S.[245]

Data of this quality were not found for the other two recommended measurements, 14.b and 14.c, concerning capacity factors that would indicate the status of our transmission and distribution systems.

The set of APQC interviews (Annex B) conducted during this assessment listed ranges of capacity factors to collect responses into a few bins. The chosen ranges in the interview did not provide meaningful information about capacity factors from the responding utilities' distribution equipment.

M.14.3.1 Stakeholder Influences

Our nation's electrical transmission and distribution system is regulated mostly on a federal and state-by-state basis and involves the participation of a very large number of stakeholders. More specifically,

- Policy advocates: this metric should provide evidence of clear trends for policy advocates. The metric should especially help advocates verify claims that the power grid is adequate or inadequate for the anticipated growth of electricity usage. These trends could also help support smart-grid policies that would flatten load profiles or would allow operation with smaller operational margins.
- Reliability coordinators including NERC: the three measurements of this metric measure generation, transmission and distribution margins. Capacity margin information is important for reliability coordinators and system planners to monitor.
- Generation and demand wholesale electricity traders/brokers: understanding the capacity margin within a marketplace is important for rational participation by market players. Because better knowledge can provide a competitive edge, detailed information is often now protected.
- Balancing authorities: the ability to balance load and generation is affected by the availability of generation resources and may be limited by transmission constraints that are have some reflection in the capacity metric.

[245]NERC 2007.

- Transmission providers: through Equation 14.b, this metric provides a benchmark for transmission providers concerning their relative practices for loading transmission lines.
- Distribution service providers: through Equation 14.c, this metric provides distribution-service providers a benchmark concerning their practices of loading provided distribution equipment - transformers, in this case.
- Electric service retailers: this metric provides general information over time about the effects of changes in customer energy usage. Plug-in electric vehicles, for example, are a technology that threatens to drastically change the way we use our existing electric distribution system and may have ramifications on the way retailers can supply such electrical load.
- End users: end users should benefit indirectly from improved reliability that could result from our improved understanding of the adequacy and operational margins built into our grid infrastructure.

M.14.3.2 Regional Influences

NERC[246] data for regions within the U.S. show some interesting trends. The eastern regions (SPP, SERC) and Texas (ERCOT) are presently expected to achieve the lowest summer regional peak capacity factors in the nation by 2016. These regions appear to be among those that most aggressively addressed the diminished generation-capacity margins observed in 1999-2001. Region MRO in the Midwest is presently projected to progressively become an energy importer, unable to supply its own summer peak generation by 2009. Figure M.14.2 demonstrates that projected performance of regions varies much more among them than their past performance. However, as would be expected, regions appear to alter their strategies and investments to meet their own challenges and bring their performance more in line with that of their neighbors over time.

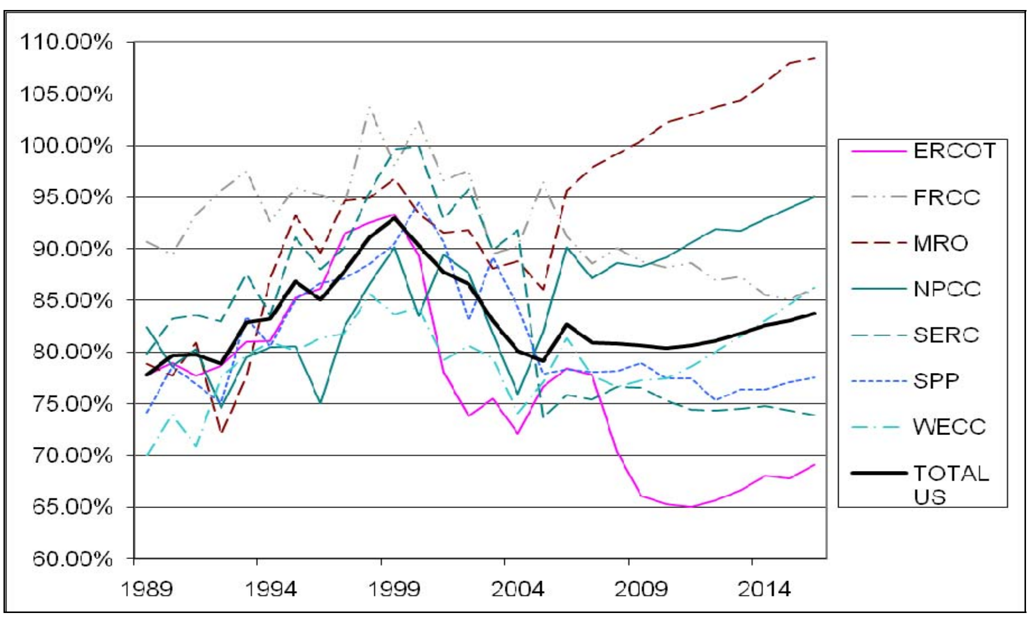

Figure M.14.2. Measured and Projected Summer Peak Capacity Factor by U.S. Region[247]

[246] NERC 2007.
[247] NERC 2007.

M.14.4.0 Challenges

Many technical, business, and policy challenges potentially hinder the use of capacity factor as a metric of smart grid evolution.

M.14.4.1 Technical Challenges

Capacity factors are not typically shared among utilities and regions. The large quantities of equipment at the generation, transmission, and distribution levels will make this metric difficult to track without accepting a statistical-sampling approach for the recommended measurements. Because changes in power-grid infrastructure occur relatively slowly, it will be challenging to obtain useful measurements with an accuracy that supports a meaningful monitoring of system trends over time using capacity-factor measurements.

M.14.4.2 Business and Financial Challenges

Because the grid spans multiple regions, industries, and functions, it is challenging to obtain the necessary information on the state of the grid. In addition, it can be hard to identify those responsible for coordinating and sharing responsibility for making enhancements. This leads to challenges in creating incentives to invest in smart-grid technology that can better manage capacity factors.

M.14.5.0 Metric Recommendations

Data were not readily found for measurements using Equations 14.b and 14.c concerning our nation’s transmission and distribution infrastructure. It is recommended that samplings be performed to estimate these metric measurements.

If future interviews of electricity providers are conducted, they should develop questions that more precisely address these metric measures.

Metric #15: Generation, Transmission, and Distribution Efficiency

M.15.1.0 Introduction and Background

Generation, transmission, and distribution are the backbone of the electric power system. As such, the efficiencies of these components of the electric power grid have been fine-tuned over the decades, and returns from traditional methods of efficiency improvement have begun to diminish. The smart grid offers the ability to increase the efficiency of these components, due to advanced, information-enabled control schemes. These control schemes create a more robust grid that runs with fewer problems, enabling generators to run at higher efficiencies and reducing losses throughout the system.

Generation, transmission, and distribution efficiencies are measured by the Department of Energy's Energy Information Administration (EIA). The EIA gathers information about the production and delivery of energy with a focus on the United States. Generation efficiency is measured in terms of heat rate, or the ratio of delivered electric energy to the energy embodied in the fuel input. Transmission and distribution efficiency are measured by the line losses incurred in transporting the energy, but other considerations, such as power quality and power reliability, are important in assessing the overall performance of these systems.

M.15.2.0 Description of Metric and Measurable Elements

(Metric 15): the energy efficiency of electric power generation and delivery (T&D).

For generation, energy efficiency is subdivided into coal, petroleum, and natural gas; non-fossil sources are not considered in this metric. The consideration of coal, petroleum, and natural gas makes up about 80% of the nation's electric power generation base. Because losses for transmission and distribution are so low in comparison, and because of a lack of finer-grained data, they are grouped together.

M.15.3.0 Deployment Trends and Projections

Figure M.15.1, from the EIA's Annual Energy Review 2007, gives a high-level view of the energy flows entering and exiting the electricity-services industry in the United States. It is important to note the high level of conversion losses prevalent in the electric power sector, amounting to roughly 64% of generated electricity lost in the generation stage.

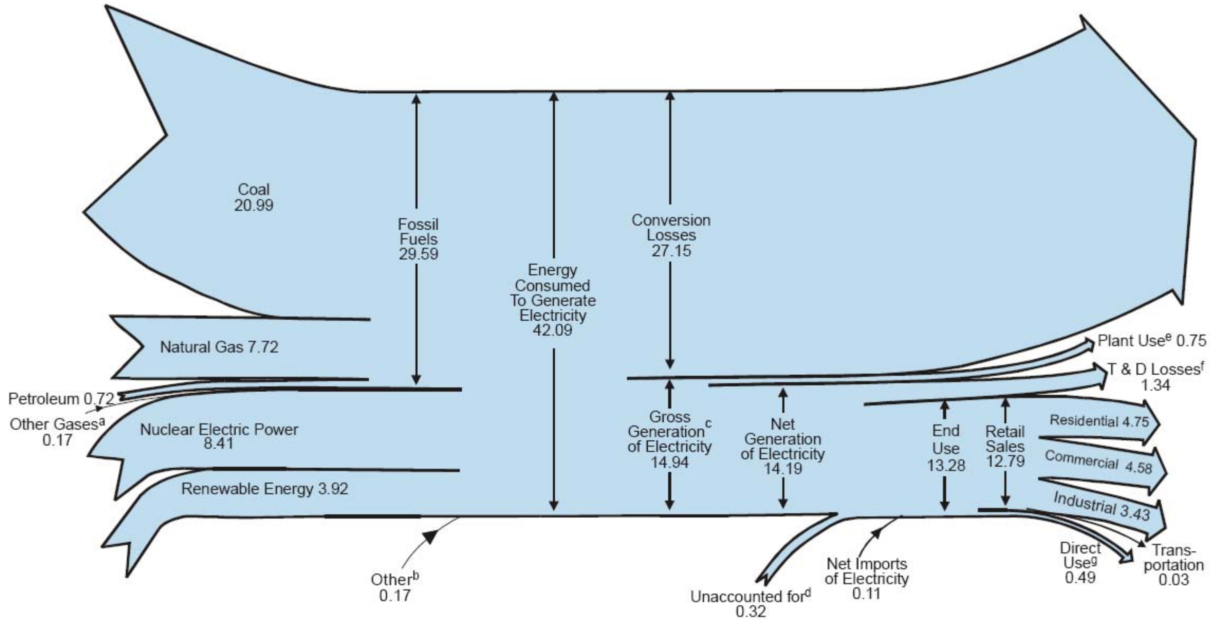

Figure M.15.1. Electricity Flow Diagram 2007 (Quadrillion Btu)[248]

Figure M.15.2 and Figure M.15.3 show the historical values for these electricity energy flows in the United States.

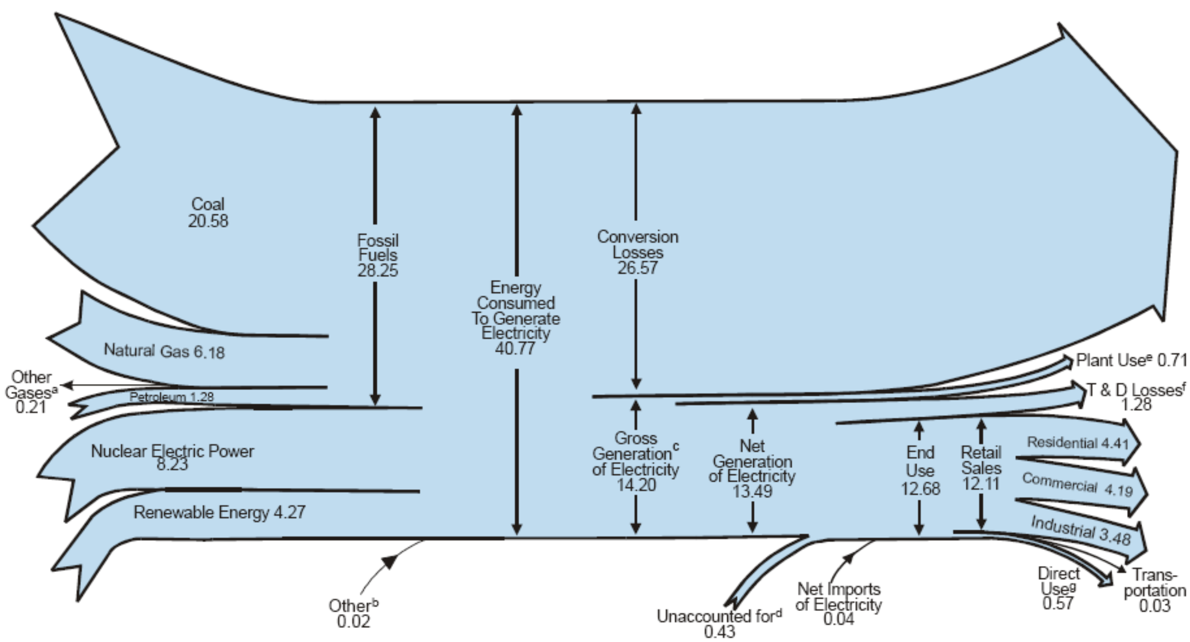

Figure M.15.2. Electricity Flow Diagram 2004 (Quadrillion Btu)[249]

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[248] Energy Information Administration (EIA). 2007. *Annual Energy Review 2007*. DOE/EIA-0384(2007), EIA, U.S. Department of Energy, Washington, D.C. Accessed October 14, 2008, at: http://www.eia.doe.gov/aer/elect.html

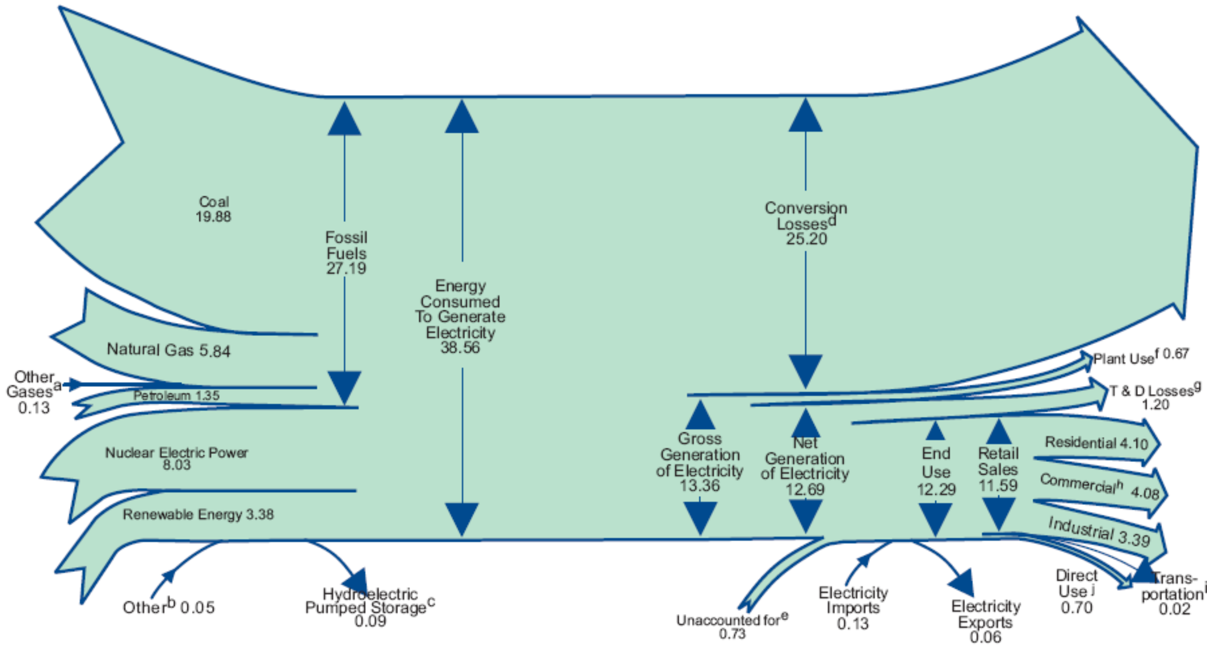

Figure M.15.3. Electricity Flow Diagram 2001 (Quadrillion Btu)[250]

It is clear from the figures that the total amount of electricity consumed has greatly increased over the past few years. The impact of generation, transmission and distribution losses has remained relatively steady, even decreasing slightly. The percentage of total energy consumed to generate electricity that is lost in generation, transmission, and distribution dropped from 68.5% in 2001 to 68.3% in 2004 to 67.7% in 2007. This is probably due to the increased use of natural gas in combined-cycle power plants, which has outpaced the growth in overall electric power use.

Figure M.15.4 delves more deeply into the efficiency of generators in the United States over time. The trends show a relatively low starting efficiency, with rapid increases for most fuels. Following rapid growth in the efficiency of coal power, the last 50 years has seen relatively stagnant efficiency rates due to the impact of clean-air legislation, which forced the industry to use more low-energy-value coal. The relative stability of coal and petroleum implies that further efficiency gains will not be easily made, while the continuing upward trend of natural-gas efficiency implies that technological advancement with this fuel is continuing.

[249]Energy Information Administration (EIA). 2004. *Annual Energy Review 2004*. DOE/EIA-0384(2004), EIA, U.S. Department of Energy, Washington, D.C. Accessed October 14, 2008, at: http://tonto.eia.doe.gov/FTPROOT/multifuel/038407.pdf

[250]Energy Information Administration (EIA). 2001. *Annual Energy Review 2001*. DOE/EIA-0384(2001), EIA, U.S. Department of Energy, Washington, D.C. Accessed October 14, 2008, at: http://tonto.eia.doe.gov/ftproot/multifuel/038401.pdf

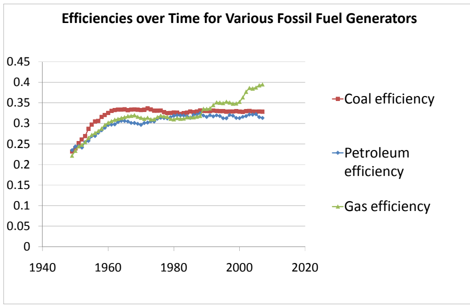

Figure M.15.4. Generation Efficiency for Various Fossil Fuel Sources over Time[251]

Figure M.15.5 shows a relatively high efficiency of transmission and distribution assets, with an almost steady level of efficiency over the past two decades. That is, T&D efficiency only grew from 92.3 percent in 1995 to 92.8% in 2007. Since 1949, more significant gains have been made, with T&D growing to 92.8% from 85.4%. In 2007, total T&D losses equaled 299.1 billion kilowatt-hours, up from 201.6 billion in 2001.

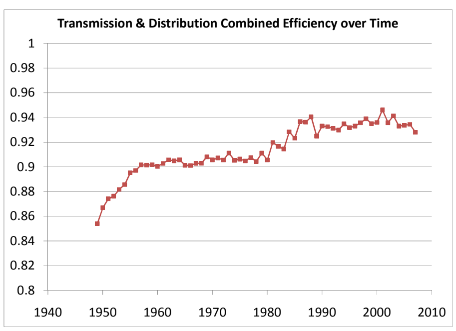

Figure M.15.5. Combined Transmission and Distribution Efficiency over Time[252]

[251]EIA 2007, *Annual Energy Review*.

M.15.3.1 Associated Stakeholders

- Electric-service retailers – who want to maximize their efficiency to increase profits
- Local, state, and federal energy policymakers (regulators) – who want to validate the performance of their state against nationwide averages and ensure that utilities are managing their assets effectively
- End users (consumers) – who want the most energy for the least amount of money
- Policy advocates (environmental groups) – who are concerned about pollution and prevention or delay of construction

M.15.3.2 Regional Influences

Regional differences emerge due to the large differences in energy resources in various parts of the country. While fossil-fuel power plants are the largest producers of electricity in the U.S., in some parts of the nation, nuclear or hydroelectric power play important roles.

M.15.4.0 Challenges to Deployment

M.15.4.1 Technical Challenges

The "easy" improvements to efficiency have already been made. New technologies that may not be familiar to utilities, including smart-grid technologies, are now required to make improvements in efficiency.

M.15.4.2 Business and Financial Challenges

Utility cultures with low traditional risk tolerance may not be best equipped to deal with the needs of an evolving marketplace. While there are plenty of high-cost infrastructure improvements, such as superconducting cables, energy-storage options, and others, these options are still high cost and work primarily for niche problems. Significant improvements in energy efficiency will require active involvement by the utility to manage demand-side efficiency and demand-side participation to reduce peak loads, as much of the generation, transmission, and distribution assets have been optimized already. Improving price transparency and customer participation will be vital in managing the electric power system efficiently in the future. This will help utilities balance capital cost, efficiency, and asset utilization.

Energy efficiency is the cheapest source of energy. While many of the largest assets have been without significant improvement for decades, investments in new technologies can provide new opportunities for utilities to make efficiency gains. While the United States has focused on incremental improvements in efficiency, other countries have made more technology-driven deployments of new technologies. Some Japanese utilities, for example, had exhibited generation, transmission, and distribution efficiencies similar to those of the United States until the past two decades, but Japanese utilities continue to make gains while the efficiency of utilities in the United States stagnates. This is because Japanese utilities have invested heavily in automation and smart-grid technology, with some utilities having almost 100% substation and generation automation. Figure M.15.6 shows some efficiency and automation information for a Japanese utility. The ability of U.S. utilities to improve efficiency levels will depend on the regulatory environment for deploying smart-grid technologies.

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[252] EIA 2007, *Annual Energy Review*.

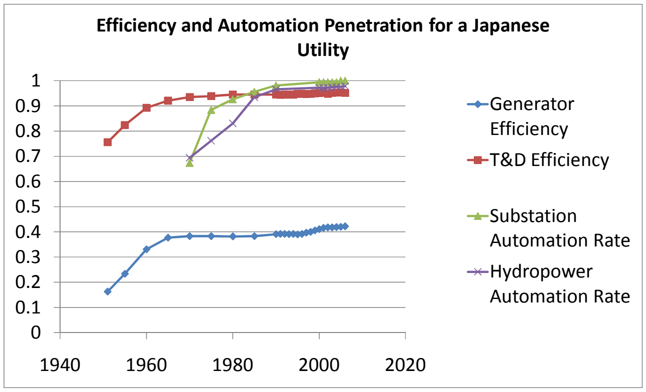

Figure M.15.6. Efficiency and Automation Information for a Japanese Utility[253]

M.15.5.0 Metric Recommendations

The electricity flow diagram data collected and reported by the EIA is crucial for this metric and needs to be updated regulary. It should also include emerging technologies in the various generation and storage areas.

[253]Tokyo Electric Power Company (TEPCO). *Corporate Information. Facts and Figures. Steam Power Thermal Efficiency and Transmission / Distribution Loss Ratio.* p.127. TEPCO, Tokyo, Japan. Accessed November 25, 2008 at http://www.tepco.co.jp/en/corpinfo/overview/facts-e.html

Metric #16: Dynamic Line Ratings

M.16.1.0 Introduction and Background

Dynamic line ratings, also referred to as real-time transmission-line ratings, are a well- proven tool for enhancing the capability and reliability of our electrical transmission system. Modern dynamic line rating systems can be installed at a fraction of the cost of other traditional transmission-line enhancement approaches.

One of the primary limiting factors for transmission lines is temperature. When a transmission line current increases, the conductor heats, begins to stretch, and causes the power line to sag. Allowable distances between power lines and other obstacles are specified by the National Electric Safety Code (NESC).

The amount of sag in a span of transmission line primarily depends on the conductor's material characteristics and construction. While line sag can be calculated with reasonable engineering accuracy, the amount of sag an older line will exhibit is less predictable. Transmission-line owners typically use survey techniques to verify the sag condition of their lines.

A standard practice is to apply a fixed rating, which usually is established using a set of conservative assumptions (i.e., high ambient temperature, high solar radiation, and low wind speed), to a transmission line. In contrast, dynamic line ratings utilize actual weather and loading conditions instead of fixed, conservative assumptions. By feeding real-time data into a dynamic line rating system, the normal, emergency, and transient ratings of a line can be continuously updated, resulting in a less-conservative, higher-capacity rating of the line about 95-99% of the time.[254] In a particularly interesting twist, transmission of wind energy might become enhanced by dynamic line ratings given the cooling effect of wind.[255]

Seppa[256] listed three approaches that were being applied to dynamic line ratings in 1997: tension monitoring, surface-temperature monitoring, and weather-based ratings. More recent field trials also reveal some success with more direct approaches to the measurement of line sag. Seppa stated the opportunity we faced in 1999 and still face now for the application of dynamic line ratings: "Thus, we could expect to generate approximately a 10% increase in the real transmission capabilities—the equivalent of 10,000 GW-miles of construction—by equipping less than 10% of transmission lines with real time thermal ratings systems."[257]

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[254]Seppa TO. 1999. *Improving Asset Utilization of Transmission Lines by Real Time Rating*. Presented at the T&D Committee Meeting, IEEE SPM-1999. Accessed October 15, 2008 at http://www.cat-1.com/files/papers/IEEE/ImprovingAssetUtilization.pdf

[255]Oreschnick P. 2007. "Dynamic Rating Allows More Wind Generation." *Transmission & Distribution World*, November 1, 2007. Accessed October 14, 2008 at http://tdworld.com/substations/power_dynamic_rating_allows/

[256]Seppa TO. 1997. *Real Time Rating Systems*. Presented at the EPRI Workshop on Real Time Monitoring and Rating of Transmission and Substation Circuits: A Technology Increasing Grid Asset Utilization, San Diego, CA, February 26-28, 1997.

[257]Seppa 1999.

M.16.2.0 Description of the Metric and Measurable Elements

(Metric 16.a) Number of transmission lines in the U.S. to which dynamic line ratings are applied

(Metric 16.b) Percentage miles of transmission circuits operated under dynamic line ratings (miles)

(Metric 16.c) Yearly average U.S. transmission transfer capacity expansion due to the use of dynamic, rather than fixed, transmission line rating (MW-mile)

M.16.3.0 Deployment Trends and Projections

The strain on our transmission system is showing, particularly as market participants and regulators are placing new requirements on the infrastructure for which it was not originally designed, such as facilitating competitive regional markets. According to DOE, 70% of transmission lines are over 25 years old.[258]

Trends concerning the status of our nation's transmission infrastructure are perhaps best pointed out by Hirst[259] and paraphrased here: The U.S. transmission grid continues to grow; however, since 1982, the long-term growth of transmission transfer capacity has not kept up with the growth of peak demand. We approach the completion of a 30-year trend that is clearly shown by the numbers in Table M.16.1.

Table M.16.1. Comparison of Growth in Transmission Capacity and Summer Peak Demand for Three Decades[260]

	Percentage Change per Year		
	1982–1992	1992–2002	2002–2012
Transmission (miles)	1.66	0.63	0.73
Transmission (GW-miles)	1.94	0.55	0.63
Summer peak (GW)	2.82	2.68	1.87
MW-miles/MW demand	-0.85	-2.07	-1.12
Miles/GW demand	-1.12	-2.00	-1.12

Clearly, technologies like dynamic line ratings must be adopted unless we choose to reverse this long-term trend. Dynamic line ratings will provide an additional 10-15% transmission capacity 95% of the time and fully 20-25% more transmission capacity 85% of the time.[261]

Attempts to locate secondary sources with tabulations of the suggested measurements were unsuccessful. The number of locations where dynamic line rating is practiced appears to be small, monitoring only a fraction of the nation's transmission lines. According to interviews conducted for this

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[258]Anderson KL, D Furey, and K Omar. 2006. "Frayed Wires: U.S. Transmission System Shows It's Age." *Fitch Ratings*, October 25, 2006:1-15.
[259]Hirst E. 2004. *U.S. Transmission Capacity: Present Status and Future Prospects*. Prepared for Edison Electric Institute and Office of Electrical Transmission and Distribution, U.S. Department of Energy, Washington, D.C. Accessed October 14, 2008 at
http://www.eei.org/industry_issues/energy_infrastructure/transmission/USTransCapacity10-18-04.pdf
[260]Hirst 2004.
[261]Seppa 1997.

report (see Annex B), on average, only 0.5% of respondents' conductors were dynamically rated, and that number dropped to 0.3% when weighted by the number of customers served by each respondent.

The following is a sampling of products identified as being available, or nearly available, for installation in the nation's transmission system:

- The Valley Group, Inc., CAT-1 system and related products—A cable-tension type system launched in 1992 and tested at locations including SDG&E.[262] The company[263] has installed 300 of these systems, including systems at about 20 of the United States' largest utilities.
- Shaw Power Technologies, Inc., ThermalRate™ system—a weather-based system announced to be available in 2004 and soon to be applied by SaskPower.[264]
- EPRI Quasi-Dynamic Rating approach—a weather-based approach.[265]

M.16.3.1 Stakeholder Influences

There are numerous stakeholders that can be impacted by the successful deployment of dynamic line rating technologies, but the three primary stakeholders include:

- Products and services suppliers including IT and communications—producers of generation, control, and communications equipment that enable dynamic line rating systems are significant stakeholders.
- Transmission providers—depending on the size and location, the insertion of dynamic line rating technologies into existing power transmission assets could enhance asset capacity and defer expensive new infrastructure investments (i.e., new transmission lines).
- End users (customers)—successful deployment of dynamic line rating technologies will result in a power grid that has higher capacity and is more reliable. In addition, electricity customers' costs can remain low through the avoidance of costs associated with installing new transmission lines.

M.16.3.2 Regional Influences

IOUs and transmission-only companies (TRANSCOs) have taken the lead in making investments in expanding the capacity of existing infrastructure and attempting to site and construct new infrastructure.[266] The actions of state and local regulators will continue to have a profound influence on investment decisions in the transmission infrastructure.

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[262] Torre W. 1999. *Dynamic Circuit Thermal Line Rating.* Report P600-00-36. San Diego Gas and Electric, San Diego, California. Accessed October 15, 2008 at http://www.energy.ca.gov/reports/2002-01-10_600-00-036.PDF

[263] TVG—The Valley Group, Inc. 2008. *Products: CAT-1 Transmission Line Monitoring System*. The Valley Group, Ridgefield, Connecticut. Accessed October 14, 2008 at http://www.cat-1.com/.

[264] Thompson N and D Lawry. 2008. "Getting Equipped: SaskPower Uses Dynamic Rating to Increase Line Capacity." *Utility Automation & Engineering T&D*, June 2008. Accessed October 14, 2008 at http://uaelp.pennnet.com/display_article/331131/22/ARTCL/none/none/1/Getting-Equipped:-SaskPower-Uses-Dynamic-Rating-to-Increase-Line-Capacity/

[265] EPRI - Electric Power Research Institute. 2006. *Maximize Overhead Line Ratings through Quasi-Dynamic Rating.* Palo Alto, California. Accessed October 2008 at http://mydocs.epri.com/docs/public/000000000001012135.pdf.

[266] Anderson et al. 2006.

No region is immune to the persistent trend in which transmission growth has been outpaced by demand growth (See Hirst[267] for details about this trend in each U.S. region). One can observe, however, that the WECC and MAPPs region maintain their transfer-capacity-to-peak demand ratios up to 4 times higher than others. This pattern is, we suggest, a result of longer transmission distances and more separated population centers in these regions compared to other U.S. locations.

M.16.4.0 Challenges

Unfortunately, there are several identified barriers that may prevent or significantly reduce the growth in the expanded capacity of existing transmission lines in the United States. Public policy has found it difficult to facilitate stakeholders in making transmission system capacity enhancements. As is similar in other industries, regulatory barriers and their economic impacts are more significant in challenging deployment than the technical challenges.

M.16.4.1 Technical Challenges

The goal of dynamic line rating is to enable higher capacity utilization of existing transmission lines. Unfortunately, other limiting factors such as voltage instability and transient stability can also significantly affect transmission-line transfer capacity more than the thermal limitations being monitored by dynamic line ratings.

Besides the equipment associated with measurements for calculating dynamic line ratings, the measurement information must be communicated to system control centers. The SCADA, state estimation, and analysis applications run in the control center must have the features that take dynamic line rating information and continually refresh the alert and alarm mechanisms within the applications so that the operator is notified of potential violations and harmful situations. Typical control center applications deal with seasonal changes in line ratings, but must be augmented to accept dynamic line rating measurements.

M.16.4.2 Business and Financial Challenges

Because the grid traverses multiple regions, industries, and functions, it is challenging to obtain the necessary information on the state of the grid and to know who is responsible for coordinating and sharing responsibility for making enhancements. This leads to challenges in facilitating investment in additional capacity.

M.16.5.0 Metric Recommendations

Inadequate data were available to quantitatively assess the suggested measurements in this metric. A small number of sites exist where dynamic line rating is practiced, and that number is growing. However, a more comprehensive interview approach with representative service providers will be needed to quantitatively identify, track, and measure the advantages achieved at those sites.

[267] Hirst 2004.

Metric #17: Customer Complaints regarding Power Quality Issues

M.17.1.0 Introduction and Background

This section examines customer complaints regarding Power Quality (PQ). PQ is a simple but subjective term that describes a large number of issues found in any electrical power system. The definition of a PQ incident varies widely, depending on the customer being served. Customers are affected by PQ incidents differently according to their needs. Residential customers tend to be affected more by sustained interruptions, whereas commercial and industrial customers are troubled mostly by sags and momentary interruptions. Avoltage sag, as defined by IEEE Standard 1159-1995, is a decrease in root-mean square (RMS) voltage at the power frequency for durations from 0.5 cycles to 1 minute, reported as the remaining voltage.[268] Momentary interruptions are usually just a few seconds but can last up to a minute whereas sustained interruptions are usually between one and five minutes.

The smart-grid system has the ability to offer several pricing levels for varying grades of PQ, which is expected to give customers more choices. Currently, the standard goal for utilities in relation to power interruptions is 3-4 "nines." Three nines represent 99.9% reliability and correspond to an outage time of 8.76 hours per year while 4 nines (99.99%) are approximately 1 hour of downtime per year. Premium power of 6-9 nines (99.9999% - 99.9999999%) would allow only 31 seconds to .03 seconds of interruption, respectively.

For those customers who are deemed power sensitive, the extra cost of premium power would be a worthwhile investment when compared to the lost revenue from a loss of power. A smart grid will utilize advanced controls to allow for rapid diagnosis and solutions to PQ events as well as decrease the number of PQ disturbances from weather events, switching surges, line faults, and harmonic sources. The grid will also moderate consumer electronic loads by limiting the level of electrical current harmonics a consumer load is allowed to produce.[269]

M.17.2.0 Description of Metric and Measurable Elements

(Metric 17): *the percentage of customer complaints related to power quality issues (excluding outages).*

M.17.3.0 Deployment Trends and Projections

Power-quality incidents in the past have been rather hard to observe and diagnose because of their short interruption period. The increase in power-sensitive and digital loads has forced us to more narrowly define PQ. For example, 10 years ago a voltage sag might be classified as a drop of 40% or more for 60 cycles, but now it may be a drop of 15% for five cycles.[270]

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[268]Institute of Electrical and Electronics Engineers (IEEE). 1995. *Recommended Practice for Monitoring Electric Power Quality.* No. 1159-1995, IEEE, Piscataway, New Jersey.
[269]National Energy Technology Laboratory (NETL). 2007. *A System View of the Modern Grid. Vol 2.* NETL. Accessed October 16, 2008, at:
http://www.netl.doe.gov/moderngrid/docs/ASystemsViewoftheModernGrid_Final_v2_0.pdf
[270]Kueck JD, BJ Kirby, PN Overholt, and LC Markel. 2004. *Measurement Practices for Reliability and Power Quality: A Toolkit of Reliability Measurement Practices.* ORNL/TM-2004/91, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Accessed November 18, 2008 at

Several power-quality studies have been completed in the United States over the past couple of decades. A 1991 paper compares three of these studies.[271] This paper cites studies by IBM (1969-1972 Allen-Segall study) and AT&T (1977-1979 Goldstein-Speranza study). A third and considerably larger study was conducted by National Power Laboratory (NPL) in the early 1990s. The consistent conclusion in all three studies was that disturbances occur and a need for different grades of power is necessary to protect sensitive loads. Comparing the studies and assessing trends, however, is more difficult as each study used different definitions, parameters, and instrumentation. NPL filtered data to compare it to the IBM and then the AT&T surveys in their AC Power Quality Studies paper. The comparison with the IBM study found a decrease in total disturbances per month and a 65% decrease in impulses, but an increase of 150% in outages and an increase of 251% in sag disturbances. The comparison between NPL and AT&T found a 20% decrease in sags, a 151% increase in impulses, an 85% increase in outages, and surges up 300%. Impulse and sag measurements are contradictory, which is likely because of different event definitions and threshold levels used in the IBM and AT&T surveys. Since these studies were completed, the IEEE has established suggestions for power-line settings to allow for more consistent measurement. Settings for 120V loads are shown in Table M.17.1.

Table M.17.1. IEEE Suggested Threshold Settings for 120 V Loads[272]

	Category	Suggested setting	Comments
Conducted phase voltage thresholds	Sag	108 V rms	Minus 10% of nominal supply voltage
	Swell	126 V rms	Plus 5% of nominal supply voltage
	Transient	200 V	Approximately twice the nominal phase-to-neutral voltage
	Noise	1.5 V	Approximately 1% of the nominal phase-to-neutral voltage
	Harmonics	5% THD	Voltage distortion level at which loads may be affected
	Frequency	±Hz	—
	Phase imbalance	2%	Voltage imbalance greater than 2% can affect equipment. (Three-phase induction motors should be derated when operated with imbalanced voltages [B11]).
Conducted neutral-to-ground differential voltage thresholds	Swell	3.0 V rms	Typical level of interest for neutral and/or ground problems
	Impulsive transient	20 V peak	Ten to twenty percent of phase-to-neutral voltage
	Noise	1.5 V rms	Typical equipment susceptibility level
Current thresholds	Phase/neutral current	Normal load current on true rms basis	Load current threshold may need to be raised well above normal load current, depending on the desired data and the amount of fluctuation in load current.
	Ground current	0.5 A true rms	Consider Section 250-21 of the NEC [B2] for safety, as well as noise currents, that lead to objectionable voltages, from both safety and data error points of view.
	Harmonics	20% THD (for small customers) to 5% THD (for very large customers)	Measured at service entrance (point of common coupling), and relative to maximum demand load current (refer also to IEEE Std 519-1992 [B13]); harmonic distortion reference values or measurements at a subpanel should be chosen relative to concerns about effects of harmonics on equipment in the circuit that is being monitored such as neutral sizing, transformer loading and capacitors.

http://www.ornl.gov/sci/engineering_science_technology/eere_research_reports/power_systems/reliability_and_power_quality/ornl_tm_2004_91/ornl_tm_2004_91.pdf.

[271] Dorr DS. 1991."AC Power Quality Studies: IBM, AT&T and NPL." *13th International Telecommunications Energy Conference, Kyoto, Japan November 5-8, 1991* pp. 552-559.

[272] Institute of Electrical and Electronics Engineers (IEEE). 1995. *Recommended Practice for Monitoring Electric Power Quality.* No. 1159-1995, IEEE, Piscataway, New Jersey.

A loss of power or a fluctuation in power causes commercial and industrial users to lose valuable time and money each year. Cost estimates of power interruptions and outages vary. A 2002 study prepared by Primen concluded that power quality disturbances alone cost the U.S. economy between $15-24 billion annually.[273] The EPRI in 2001 estimated power interruption and power quality cost at $119 billion per year,[274] and a more recent 2004 study from LBNL estimated the cost at $80 billion per year.[275] It should be noted that the two latter studies also include reliability costs as well as power-quality costs. The cost of a momentary disruption to various users in dollars per kilowatt is shown in Table M.17.2 below.

Table M.17.2. Disruption Cost by Industry[276]

	Cost of Momentary Interruption ($/kW demand)	
Category	**Minimum**	**Maximum**
INDUSTRIAL		
Automobile manufacturing	$5.0	$7.5
Rubber and plastics	$3.0	$4.5
Textile	$2.0	$4.0
Paper	$1.5	$2.5
Printing (newspapers)	$1.0	$2.0
Petrochemical	$3.0	$5.0
Metal fabrication	$2.0	$4.0
Glass	$4.0	$6.0
Mining	$2.0	$4.0
Food processing	$3.0	$5.0
Pharmaceutical	$5.0	$50.0
Electronics	$8.0	$12.0
Semiconductor manufacturing	$20.0	$60.0
COMMERCIAL		
Communications, information processing	$1.0	$10.0
Hospitals, banks, civil services	$2.0	$3.0
Restaurants, bars, hotels	$0.5	$1.0
Commercial shops	$0.1	$0.5

The research team conducted interviews in support of this report with 21 companies collectively serving 0.8-1.2 billion megawatt hours of generation annually and a peak demand of 150,000-175,000 megawatts. The research team asked respondents to estimate the percentage of customer complaints related to PQ issues (excluding outages). The utilities indicated that 3.1 percent of all customer complaints were related to PQ issues. This value represents a weighted average amount.

Recently, PQ has moved from customer-service problem solving to an integral part of the power-system performance process. The design of PQ devices meant to monitor quality has not changed significantly in the past decade. Instead, the hardware, firmware, and software utilized by these systems have advanced dramatically. These changes are driven by market demands, standardization of measurement techniques and communication protocols, specialized large-scale integrated circuits, and

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[273] McNulty S and B Howe. 2002. *Power Quality Problems and Renewable Energy Solutions.* Prepared for the Massachusetts Renewable Energy Trust.
[274] Electric Power Research Institute (EPRI). 2001. *The Cost of Power Disturbance to Industrial and Digital Economy Companies.* Consortium for Electric Infrastructure to Support a Digital Society. EPRI, Palo Alto, California. Accessed October 18, 2008, at http://www.epri-intelligrid.com/intelligrid/docs/Cost_of_Power_Disturbances_to_Industrial_and_Digital_Technology_Companies.pdf.
[275] Hamachi LaCommare K and J Eto. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. LBNL-55718, Lawrence Berkeley National Laboratory, Berkeley, California. Accessed October 14, 2008, at http://certs.lbl.gov/pdf/55718.pdf.
[276] NETL 2007.

improvements in software methodology. The latest PQ devices use web browsers to allow for remote access of information.

M.17.3.1 Associated Stakeholders

There are a number of stakeholders engaged in PQ issues:

- Electric service retailers working toward providing better PQ to customers.
- End users (residential, commercial and industrial users) needing consistent power quality.
- Regulators interested in enhancing PQ and better serving the customer base.

M.17.3.2 Regional Influences

Regional differences surface for several reasons, such as climate, design of the distribution system, and maintenance levels. The geographical features of an area, the number and type of customers (residential, commercial, or industrial), the economic health of a region, and the fact that utilities have different distribution systems also lead to PQ problems. Therefore, interruption costs for comparable customers in different regions could vary significantly.

Also, PQ is dependent on the number and type of customers in a region. PQ related interruption costs for a similar type of customer will be different depending on the region of the country, what industries predominate in the area, the local demographics, and economic health of the region.

M.17.4.0 Challenges to Deployment

Measuring PQ presents a challenge because of the regional influences of a given area and the inconsistency in definitions and reporting of PQ. Different geographical issues, such as weather, terrain, and demographics, create inconsistencies that make it difficult to compare PQ across regions. The PQ of electrical service is a bit more complex to measure then the reliability since PQ events are harder to observe and diagnose because of their short duration and the fact that definitions and standards are evolving.

M.17.4.1 Technical Challenges

Standards organizations have not created standards for categories of PQ that consumers can choose from according to their needs. Standards for various grades of delivered power could serve as the basis for differentiated PQ pricing. Also, more distinct definitions and better reporting and handling of evolving PQ issues would help clarify the topic, which is still not well understood.

M.17.4.2 Business and Financial Challenges

There are costs associated with implementing advanced PQ devices that some may not be willing to assume. Devices include those used by the utilities to monitor and diagnose problems, and devices used by the end user that depend on the size and type of the critical load. Typically, end-user devices are categorized in three groups: individual operations (controls or individual equipment protection), sensitive sub-facilities (individual circuit protection), and the entire load (at the electric service entrance). PQ enhancing devices are still too expensive to be widely used. As more cost-effective designs are developed and supply increases in return, prices should come down.

FERC, in a policy statement on matters related to bulk power-system reliability, stated that public utilities may be uncertain about spending significant amounts of money without reassurance they will be able to recover it. The report goes on to note that:

> *"Regulators should clarify that prudent expenditures and investments to maintain or improve bulk power system reliability will be recoverable through rates. The Commission also assures public utilities that they will approve applications to recover prudently incurred costs necessary to ensure bulk electric system reliability, including prudent expenditures for vegetation management, improved grid management and monitoring equipment, operator training, and compliance with NERC reliability standards and Good Utility Practices."*[277]

To provide different grades of power to consumers, a shift in standards must occur. PQ standards have not been well defined in the past and currently only provide a safety net. By implementing standards for the level of PQ customers expect to receive, it would be easier to differentiate between grades of power, thus giving end users more choices. This is particularly important for regulated T&D companies interested in selling premium power competitively while still protecting their customers receiving normal regulated service. Currently, without specific standards for each grade of power, T&D companies could appear to provide low-quality power to increase the sales of higher grade power.[278]

M.17.5.0 Metric Recommendations

Customer sentiment regarding PQ issues is captured by measuring PQ complaints by customers as a percentage of total complaints. What constitutes a PQ complaint, however, is unfortunately open to interpretation. Consideration should be given to constructing a clear definition of what constitutes a PQ complaint. In developing this definition, the research team should work closely with electric-service retailers and subject-matter experts. Further, the number of interviews should be expanded to generate a more precise assessment of this metric. Finally, future reports should also consider reporting the total number of PQ complaints while also noting the total number of complaints reported by the interviewed utilities. Reporting the total number of PQ complaints would enable a better understanding of the magnitude of the issue.

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[277] 107 FERC 61,052, Docket No. PL04-5-00. 2004. *Policy Statement on Matters Related to Bulk Power System Reliability*. Issues April 19, 2004, Federal Energy Regulatory Commission, Washington, D.C. Accessed October 14, 2008, at http://www.ferc.gov/whats-new/comm-meet/041404/E-6.pdf.
[278] Kueck et al. 2004.

Metric #18: Cyber Security

M.18.1.0 Introduction and Background

The interconnected North American grid is arguably the world's largest and most complex machine. It has achieved and sustained an enviable record of reliability through application of numerous technological and operational efficiencies, and strong regulatory oversight. The grid's complexity and interconnected nature, however, also pose a significant drawback; under the right circumstances, problems occurring in one area have the potential to cascade out of control and affect large geographical regions.

Economic forces and technology development are making the power system more dependent on information systems and external communications networks. The interconnected nature of the communications systems that support regional and interregional grid control, and the need to continue supporting older legacy systems in parallel with newer generations of control systems, further compound these security challenges. Additionally, with the advent of inexpensive microcontrollers and smart-grid implementation, there is a growing trend for increased intelligence and capabilities in field equipment installed in substations, within the distribution network, and even at the customer's premises. This increased control capability, while vastly increasing the flexibility and functionality to achieve better economies, also introduces new cyber-vulnerabilities that have not previously existed.

M.18.2.0 Description of Metric

An understanding of component and associated system vulnerabilities will be necessary to quantify cyber-security issues inherent in smart-grid deployments, particularly when these elements can be used to control or influence the behavior of the system. Assessments will be needed, both in controlled laboratory or test-bed environments and in actual deployed field conditions, to explore and understand the implications of various cyber-attack scenarios, the resilience of existing security measures, and the robustness of proposed countermeasures. Vendor adoption of these countermeasures will be critical to broadly influence the installed base of future deployments. The asset-owner utilities will remain responsible for legacy systems.

> *(Metric 18): the electric power industry's compliance with the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards* (Table M.18.1).

Designed to maintain the integrity of North America's interconnected electrical systems, the NERC CIP standards establish minimum requirements for cyber-security programs protecting electric control and transmission functions. On January 17, 2008, the Federal Energy Regulatory Commission (FERC) directed NERC to further tighten the standards to provide for external oversight of classification of critical cyber assets and removal of language allowing variable implementation of the standards. One of the areas that will likely be changed in the next revision of the standards is the removal of "reasonable business judgment" in the context of technical feasibility.

Table M.18.1. Summary of the NERC Critical Infrastructure Protection Standards[279]

NERC Standard	*Subject Area*
CIP-001-1	Sabotage Reporting
CIP-002-1	Critical Cyber Asset Identification
CIP-003-1	Security Management Controls
CIP-004-1	Personnel & Training
CIP-005-1	Electronic Security Perimeter(s)
CIP-006-1	Physical Security of Critical Cyber Assets
CIP-007-1	Systems Security Management
CIP-008-1	Incident Reporting and Response Planning
CIP-009-1	Recovery Plans for Critical Cyber Assets

M.18.3.0 Deployment Trends and Projections

The interviews with 21 service providers in Annex B of this report provides initial data with regard to industry compliance with these cyber-security standards, including the percentage of utilities that have conducted assessments at various frequencies for NERC CIP Standards 002 through 009. The interviews found that 5% of the utility respondents have indicated they have never conducted an assessment. It's not clear whether this is because they are not large enough to have an impact on the bulk electric power system or because they are still in the process of phasing in their compliance. As the timeline for mandatory compliance of all entities associated with the bulk electric system becomes fully implemented, and NERC establishes procedures for more formally tracking compliance with these standards, it will become increasingly easier to gather data and assess trends for this metric.

Table M.18.2. Sample Security Question from Interviews

Have you deployed the following security features? *(Select all that apply)*	**Responses**
a. Intrusion detection	65.0%
b. Key management systems	50.0%
c. Encrypted communications	70.0%
d. Firewalls	95.0%
e. Others (Please describe)	30.0%

While compliance with mandatory security standards is an important step toward achieving security, it is in itself not a complete measure of security. Generally, these security standards are more focused on compliance requirements, and increased compliance may not necessarily equate to increased security. Furthermore, standards can take years to develop and implement and may lag behind the cutting edge of technology deployment, particularly when the industry is in transition, as is the case with smart-grid technologies. Therefore, these metrics may be more of a lagging rather than leading indicator of the security posture of the smart grid.

[279]See Critical Infrastructure Protection Standards at www.nerc.com.

Additionally, the interview form includes a question about specific security measures that utilities are implementing. The sample results are shown in Table M.18.2. While this represents useful information and can be valuable for trending, the questions themselves are too vague to ascertain what precisely is the security posture of the smart-grid technologies vis-à-vis more broad “enterprise-wide” security measures that are employed by the utility. Clarification may also be needed about the definitions and some additional detail regarding the effeteness of these security measures (for example, the presence of a firewall does not ensure that its rules are properly implemented).

Control systems evolved in an environment of implicit trust. A properly formatted command is carried out without question by the automatic controller. In this environment, security relies on isolation. Over the years, the electric utility industry built and operated its own private communications infrastructure to control the electric power grid, using systems and protocols unique to the industry. Noise, interference, and equipment reliability were primary issues to overcome. This isolation resulted in inherent security, but was expensive to implement and maintain. Because of this, the trend has been shifting toward the use of shared communication with public networks, open and commonly used protocols, and general-purpose operating systems whose many security weaknesses are more widely known. Economic forces and technology development are making the power system more dependent on information systems and associated communications networks, particularly in the context of smart-grid systems and their inclusion of demand-side resources. The interconnected nature of these communications systems and the need to continue supporting older legacy systems in parallel with newer generations of control systems further compound the complexity and challenges of addressing this problem.

In addition, data exchange interactions between businesses result in handing off data security responsibility at the interface between the interacting parties. Ensuring that information privacy is protected and that cyber-security vulnerabilities are addressed on either side of an interface requires a coordination of business processes, particularly when the data may transition to different technologies and protocols. Designed-in security approaches are only now emerging.

Unlike the threats from component failures, extreme weather, or natural disasters that are mitigated by highly effective and well-developed contingency and restoration practices, the cyber-threat landscape is only beginning to be effectively addressed through common industry standards and best practices.

M.18.3.1 Associated Stakeholders

- End users: Cyber-security breaches can greatly affect consumers, not only from disruptions when the electric infrastructure is compromised, but also because a smart grid incorporates participation by consumers’ automation systems. Electricity-related information-technology connectivity may provide a new path for a cyber attack that might affect a facility’s operation or obtain private information. Each consumer group needs to assess its vulnerability and develop an appropriate security posture.
- Electric service retailers and wholesale electricity traders: These entities connect to customer systems, market operators, and infrastructure system operators with greater linkages as smart grid trends progress. Security issues must be assessed across their operations with cooperation between all transacting business systems.

- Distribution and transmission service providers, balancing authorities, and reliability coordinators: The protection of the infrastructure is a national concern. The NERC CIP requirements, while modest, are being refined, with recognition for the importance of security.
- Products and services suppliers: Information technology, business systems, and engineering vendors have shown interest in developing or updating product offerings to address security needs. However, real change occurs when customers specify security features as requirements for their purchases.
- Energy policymakers and advocates: The idea that the electric infrastructure could be crippled by a cyber security breech is disconcerting to those protecting the public interest. Policymakers are searching for ways to ensure that cyber-security issues are addressed. For example, FERC is pushing NERC to strengthen the CIP standards, as the balance between cost, risk, and effective measures continues to mature.

M.18.3.2 Regional Influences

Approaches to address cyber security issues should not vary greatly internationally. State-specific issues may arise because of different laws relating to transparency of information associated with Freedom of Information Act issues. For example, in California, a state-sponsored organization such as the California Independent System Operator may find it difficult to protect sensitive information from being disclosed because of state sunshine laws. There will also continue to be international and national standards in the cyber-security area that may compete in technology and policy approaches.

M.18.4.0 Challenges to Deployment

M.18.4.1 Technical Challenges

The electric system of the future could become much more vulnerable to disruption by skilled electronic intrusion originating either internally or externally. Compounding the problem, security is often neglected or introduced as an afterthought rather than being incorporated as a core component in the development and deployment of these new technologies and applications.

Because cyber security is largely a defensive practice when applied to protecting against a steady flow of active exploits, the threat to computer and control systems is never completely ameliorated. A vital need in the electricity industry is the development of new approaches for inherent security: components and systems with built-in security capabilities. Coordination is also needed between these approaches and techniques appearing in other industrial, commercial building, and residential systems that interact with the electric system.

Complexities and interdependencies are poorly understood. These include internal and external issues with the electricity infrastructure. Examples of internal interdependencies are market-based systems for buying, selling, and wheeling power throughout the network – while they are not directly connected to the control systems providing real-time operation of the grid, there are sometimes subtle dependencies that could cause reliability implications if security in these systems were compromised. An example of an external interdependency is reliance on other infrastructures, such as communication, that is vital to the operation of the electricity infrastructure. Systemic failures that propagate among these dependency seams can create failure modes that are difficult to predict and mitigate.

Finally, it is not clear whether there is general consensus among the industry stakeholders regarding the threat, which leads to inconsistent views regarding the appropriate level of attention and investment needed to achieve appropriate levels of security.

M.18.4.2 Business and Financial Challenges

The key challenge will be to maintain reliability in a vastly more “connected” electric industry under threats that could involve multiple, distributed, and simultaneous or cascading incidents – whether accidental or deliberate. Steps should be taken to enhance the security of real-time control systems using sound information security practices. In the future, all control systems for critical applications should be designed, installed, operated, and maintained to survive an intentional cyber assault with no loss of critical function.

All stakeholders share a common interest in deterrence, intrusion detection, security countermeasures, graceful degradation and emergency backup and rapid recovery. While the NERC CIP-002 through CIP-009 standards are an effective start to begin addressing cyber security and are achieving increased awareness and action within the electric utility industry, there is growing recognition that they have not yet achieved their ultimate purpose – defining uniform standards that if implemented can provide adequate security against cyber threats to the electric infrastructure. Problems with the standards include provisions for entities to self-define what they will protect and how they will protect it; this has resulted in a patchwork of mitigation measures that is more focused on compliance than security. In addition, there is concern that the standards have loopholes associated with communications and certain types of control systems. There is an urgent need to quickly address these issues with the adoption of new versions of these standards, but the standards development and approval process is literally measured in years. More work to transition the industry mindset from a culture of compliance to a culture of security needs to be done.

Another issue is inconsistent regulatory support that electric utilities have associated with cost recovery for necessary security enhancements. The electricity regulatory landscape is complex with multiple stakeholders at the federal, state, and local levels. Not all regulatory jurisdictions have recognized security as a recoverable cost, and other utilities are constrained in implementing security because it would cause preexisting rate cases to be reopened at great expense and risk to the company.

M.18.5.0 Recommendations for Future Measurement

A more mature evaluation of cyber security will evolve toward self-assessment tools to provide enduring capabilities for vendors, system integrators, and asset owners to afford appropriate security commensurate with the risk associated with the application. This will empower industry to be responsible for making reasoned and informed tradeoffs.

Fundamentally, systems will be required that are inherently secure and robust. Research and development will be needed to develop these systems. Metrics to measure their effectiveness will need to be defined.

PNNL, with ANL and INL, has been tasked by DOE to prepare a report for Congress with answers to the questions posed in Section 1309 of Title XIII of the Energy Independence and Security Act of 2007:

1. How can smart-grid systems help make the nation's electricity system less vulnerable to disruptions caused by intentional acts against the system?
2. How can smart-grid systems help restore the integrity of the nation's electricity system subsequent to disruptions?
3. How can smart-grid systems facilitate nationwide, interoperable emergency communications and control of the nation's electricity system during times of localized, regional, or nationwide emergency?
4. What risks must be taken into account because smart-grid systems may, if not carefully created and managed, create vulnerability to security threats of any sort, and how such risks may be mitigated?

This report will be prepared with industry input through the first half of Fiscal Year 2009, and will help provide greater clarity around cyber-security issues associated with smart-grid technologies with suggested metrics that should be useful for future reports of this nature.

Metric #19: Open Architecture/Standards

M.19.1.0 Introduction and Background

The vision for the smart grid hinges on the ease of integration of intelligent equipment and systems to enable their collaboration and coordination to achieve local, regional, and national energy objectives. Given the abundance of such components, the information-technology integration approach must be scalable and the connectivity agreements in an area, such as integrating building resources with the electric system, must converge to a few commonly supported practices. Though such practices will change as technology solutions advance, commercially viable approaches will consider a measured level of stability for interface definitions that support legacy systems and the introduction of new technology. The term "open" is intended to mean that the specification, approach, or resource that facilitates system integration is accessible to all interested parties without unreasonable barriers to entry.

The Smart Grid Implementation Workshop identified related concepts in this area, including the percentage of the electric system that is networked to standards, the number of products with end-to-end interoperability certification, and the level of deployment of common communications infrastructure. Although the proposed metrics are relevant, obtaining measurements for these concepts is difficult.

While direct measures of openness or standards adoption are difficult obtain, the conjecture that any of these metrics would accurately indicate progress toward enabling a smart grid is dubious. One promising approach is to use concepts derived from the Carnegie Mellon Software Engineering Institute and the software capability maturity model (CMM).

Widespread adoption of openly available standards and architectural approaches is an indication of maturity in technology and business practices. A smart grid, with its diverse stakeholders, represents a relatively immature movement composed of many parties, each with its own heritage in business practices and standards. A convergence of approaches may come from the large penetration of Internet-based technology and methodology, but it will take time to develop and materialize. The development of software in general experienced a similar situation; there were many methods, languages, and processes for developing software in different communities, with different levels of success. Rather than pick a "winner," the Software Engineering Institute (SEI) at Carnegie Mellon took the approach of encouraging a culture of continuous process improvement. The result is the SEI Capability Maturity Model for Software (CMM), and subsequently, the CMM Integration (CMMI).[280]

Rather than specifying a set of standards or particular development methodology, the CMM asks organizations to specify how software is developed and managed, and then provides a ruler for gauging a level of maturity in the discipline of software development. The National E-Health Transition Authority of Australia (NEHTA) has taken these notions a step further and closer to the situation we face with system integration and interoperability in a smart grid. As with electricity, the health industry has numerous stakeholders, including government agencies, hospitals, public and private practices, insurance companies, medical products and service providers, and most of all, patients. As a step to address the interoperation of automation systems that link the complex web of business processes associated with

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[280] Software Engineering Institute. Carnegie Mellon University. 2008. [CMM] *The Capability Maturity Model for Software.* Accessed October 14, 2008, at:http://www.sei.cmu.edu/cmm/

health, NEHTA augmented CMMI to create the e-health interoperability maturity model (IMM).[281] The IMM is, "… a reference model for expressing levels of e-health organization capability on their path toward delivering better interoperability outcomes. Each capability level represents a process improvement, referred to as an organizational maturity level. Consequently, each maturity level requires attaining the previous maturity levels, while incrementally adding new capability and bringing new benefits. There are five maturity levels identified, namely Initial, Managed, Defined, Measured and Optimized." Figure M.19.1 explains these levels.

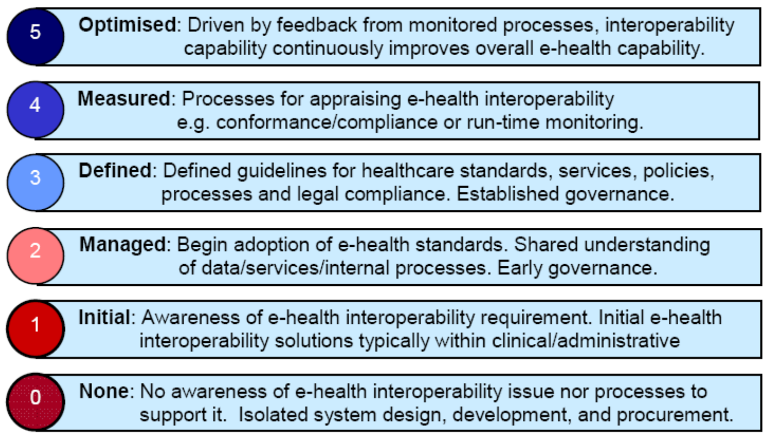

Figure M.19.1. Interoperability Maturity Levels[282]

Note, the interviews with electric service providers used to help characterize the status of smart grid deployment in this report was augmented from a similar approach used to measure intelligence in a utility enterprise and called the Intelligent Utility Network Maturity Model (IUN/MM) [Annex B].

M.19.2.0 Description of Metric and Measurable Elements

(Metric 19) Interoperability Maturity Level – the weighted average maturity level of interoperability realized among electricity system stakeholders.

The method to measure progress in open architecture and standards is to develop a smart-grid Interoperability Maturity Model (IMM) and then survey interactions between stakeholders to measure the interoperability maturity level in specific smart-grid areas that emphasize the interfaces between organizational boundaries. Examples of these boundaries include the residential, commercial building, and industrial plant interfaces with the electricity service provider. Another is the balancing-authority to reliability-coordinator interface.

As this work has yet to be undertaken, the remaining discussion provides a qualitative view of progress of open architecture and standards.

[281]National E-Health Transition Authority (NEHTA). 2007. *Interoperability Maturity Model, Version 1.0*. NEHTA, Sydney, Australia. Accessed October 14, 2008, at www.nehta.gov.au/index.php?option=com_docman&task=doc_download&gid=220&Itemid=139
[282]NEHTA 2007.

M.19.3.0 Deployment Trends and Projections

The scope of the smart grid includes the connectivity that occurs in the transmission and distribution areas (such as substation automation), the control centers (such as SCADA information sharing with other applications and between operating organizations), and the consumer-side resources (such as commercial equipment and distributed generation and storage). Efforts have been underway for some time to integrate equipment and systems in substation automation, control centers, enterprise systems, and within industrial, commercial-building, and residential energy management systems. The level of integration is increasing in each of these areas, and the amount of integration between these areas is also increasing.

Standards and openness are also advancing in terms of the layers of agreement that must align. The GridWise® Architecture Council (GWAC)[283] proposes three major categories that need to be aligned to achieve interoperability: technical, informational, and organizational (see Figure 2). The bottom levels focus on information technology (I), while the top levels focus on electric energy (E). The status of these layers as they pertain to the smart grid follows.

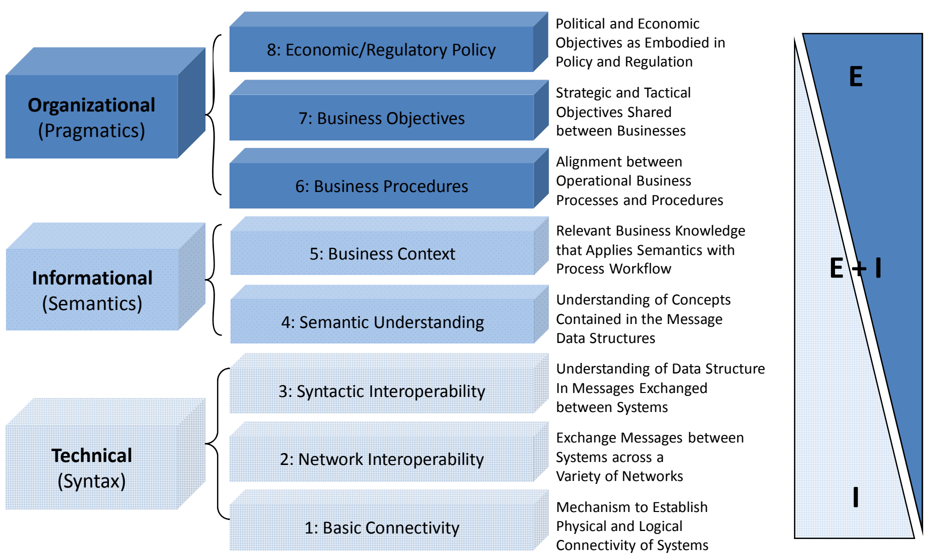

Figure M.19.2. Interoperability Categories (from GWAC Interoperability Context-Setting Framework)

The technical categories involve network connectivity and syntax. Though there are many lower-level protocols to handle communications networks (e.g., cable, twisted pair, fiber optics, wireless, broadband power line carrier), and protocols with associated syntax (e.g., Ethernet, TCP/IP, Zigbee, IEEE 802.11, Wi-Fi), the standards for these technologies are mature to the point that an assortment of communications products are now procured and integrated to support many applications. Layered on top of these communications networks are general-purpose protocols to support SCADA activities. Each

[283]GridWise Architecture Council. 2008. *Interoperability Context-Setting Framework, v1.1*. Accessed November 12, 2008 at http://www.gridwiseac.org/pdfs/interopframework_v1_1.pdf

business community has developed its own SCADA-like protocols to meet its performance and cost requirements. In each community, the trend has been to move away from proprietary communications networks, protocols, and syntax toward widely available standards supported by various product offerings.

The informational categories are less mature than those in the technical area. The SCADA information models tend to generically describe equipment, measurements, and actuators. The understanding of the equipment and how it fits within a business process is held in specification documents and the minds of the programmers and integrators. Thus, there is a high level of customization for each application. Anything approaching standardization is contained in best practices and the knowledge gained through experience. Exceptions to this exist with a few automation interface standards. However, the standards emerging to support eCommerce are making significant progress with modeling the information (semantics) for specific business contexts. The Internet-based information-modeling standards (e.g., XML Schema, Resource Description Framework (RDF), and Web Ontology Language (OWL)) dominate the new standards work, while earlier approaches to information modeling continue to progress and evolve based upon the familiarity of developers in targeted communities.

The organizational categories involve business operations and strategic decision-making. In this area, business processes are modeled using methodologies that are supported by enterprise integration and eCommerce tools and modeling techniques. These methods represent humans and machines as abstract concepts that reflect the series of actions involved in a business process. Where each human or machine application interfaces with another, the sequence, performance, information exchanged, and consequences under failure scenarios are captured in a specification. Languages continue to evolve to record these specifications and mechanically turn appropriate aspects of them into software-interface definitions and code. In particular, web services and service-oriented architecture techniques are being employed to support these higher-level concepts. Business-process modeling is virtually nonexistent in consumer-side electricity-related automation and T&D automation. It is appearing in control centers, particularly as the interface to other applications of the enterprise.

In the technical categories of network connectivity and syntax, multiple standards will continue to evolve to support the various communications media; however, bandwidth is becoming less of a problem and Internet-based approaches are likely to continue to grow as hardware and software tools make them more cost effective.

Convergence toward information modeling using UML, XML Schema, and the OWL semantic language is gaining ground. With the advent of web services and service-oriented architecture, tools and techniques for designers and implementers are making it easier to move into business-process modeling.

M.19.3.1 Stakeholder Influences

As Figure M.19.2 suggests, nearly all stakeholders are affected by the availability and adoption of integration architectures and supporting standards. In particular, the following groups are most affected:

- Consumers: the amount and reliability of participation of demand-side resources depends on integrating automation systems cost effectively.

- Electric service retailers: aggregating demand-side resources for participation in local and area system operations depends on cost-effective automation systems to coordinate with consumer systems.
- Distribution and transmission service providers: cost-effective and reliable techniques require standards. Given the scale and long life of the equipment, approaches must be able to evolve over time and continue to integrate with legacy components.
- Balancing authorities, generators, wholesale electricity traders, market operators, and reliability coordinators: require standard enterprise-integration approaches and eCommerce standards for connectivity.
- Products and services suppliers: the maturing modularization of software systems discourages large, proprietary solutions that inhibit future competition with other suppliers. Standards are more commonly put into specifications. In addition, suppliers can be more competitive by integrating their offering with components provided by other suppliers. Less customization can allow for higher levels of productivity.
- Regulators and policy makers: Greater levels of standardization and common integration approaches can bring costs down for the consumer and foster competition.

M.19.3.2 Regional Influences

Given the global reach of international solutions providers, open architecture and standards should be encouraged internationally. Practically speaking, national-standards bodies will likely continue to have differences with their counterparts across the globe, in particular, USA, EU, Japan, China, and India. With few exceptions, the leading IT standards in use and being developed apply uniformly to all parts of a nation.

M.19.4.0 Challenges

M.19.4.1 Technical Challenges

Architectures and standards are subjects of innovation through better ideas. While agreement and adoption on standards eases integration and enables cost-effective implementations, new approaches can bring greater capability and further cost reductions. Features that focus on interfaces and that support extensions, versioning, and adaption to old and newer technologies can help support the need to evolve in the quickly changing world of technology.

M.19.4.2 Business and Financial Challenges

Flexibility is important in picking an architectural approach and associated standards. At the corporate level, a heterogeneous mixture of technologies and standards service an enterprise and its business-partner connections. A balance must be found among many factors, including the cost to move to new technology and standards, the ability to support multiple standards, the impact on productivity and competitiveness, and the risk associated with a decision. Return on investment is the classical mechanism to explore these trade-offs; however, it can be difficult to quantify the returns from moving toward solutions that manage risk and offer future alternatives.

M.19.5.0 Metric Recommendations

Future measurements of progress in this area will depend on the development of a smart grid IMM, and later, interviews with stakeholders about smart-grid applications to investigate the interoperability maturity level in specific areas of interaction. The effort to develop a smart grid IMM should review the work of NEHTA and of other related industries. It should also review integration and interoperability tools and methodology in the smart-grid area, such as is reflected in the GWAC Interoperability Context-setting Framework,[284] the EPRI IntelliGrid Architecture,[285] and work now underway by NIST to establish an interoperability framework.

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[284] GWAC 2008.

[285] EPRI-Electric Power Research Institute. *IntelliGrid[SM] Architecture.* Accessed November 12, 2008 at http://www.epri-intelligrid.com/intelligrid/techdev/intelligrid/intelligrid.html (undated webpage).

Metric #20: Venture Capital Investment in Smart Grid Startup Companies

M.20.1.0 Introduction and Background

Historically, utilities have been conservative when adopting new and emerging technologies. Regulatory barriers and the lack of direct incentives have at times failed to foster the development of technologies that enhance energy efficiency. When considering investment in smart grid technologies, utilities are also challenged by the nascent stages in which these technologies often exist, and the lack of industry standards for smart-grid technologies.

Venture capital played a major role in creating the biotechnology enterprise, the information technology market, and the communications industry. In recent years, venture-capital firms have invested increasingly in smart-grid-technology providers. These venture-capital firms have noted several investment drivers, including:

- oil prices exceeding $140 per barrel makes energy delivered by electricity (produced from all sources) more competive – the price of oil is recognized as a major indicator of prices in the energy sector, even though oil only produces a small fraction of the electricity in the U.S.
- peak demand growing at a time when energy infrastructure is in need of updating and replacement
- shrinking capacity margins
- increasing recognition of clean and efficient technologies.

Investors have increasingly concluded that these drivers point toward a future that will include smart-grid and demand-response technologies, and that those who invest early could be rewarded well.[286]

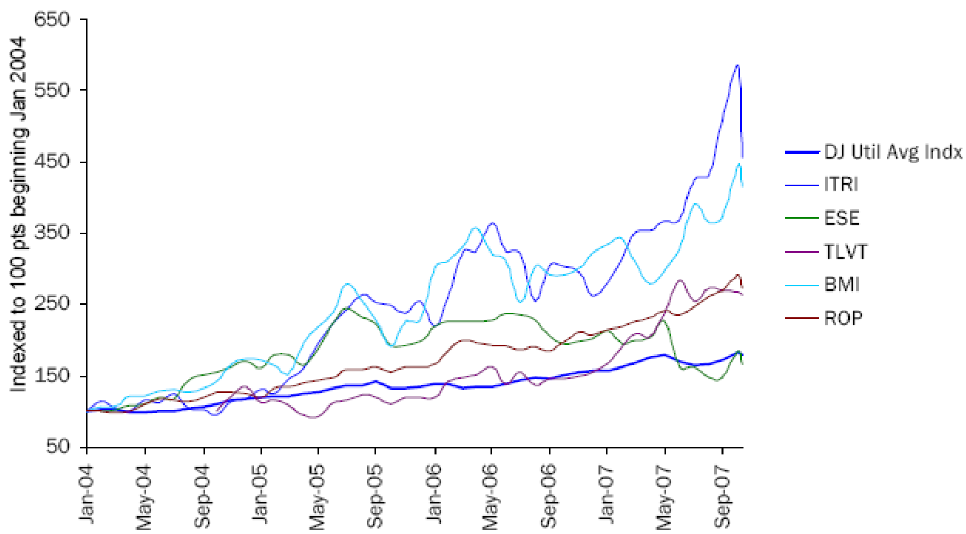

Figure M.20.1. Stock Performance of Companies Developing Smart Grid Technologies

[286]Quealy, JS. 2007. "Financial Market Assessment of Demand Response's Future." In *Southern California Edison Demand Response Forum*, Global Energy Partners, LLC, Lafayette, CA. Provided by author to researchers for this report.

Investing in companies focusing on smart-grid applications has paid significant dividends to some investors. Figure M.20.1 demonstrates that the stock performance of a small number of companies developing demand-response technologies that support the smart grid outperformed the Dow Jones Utility Average Index in the January 2004 – September 2007 time period.[287] The companies highlighted in Figure M.20.1 include Itron Inc., ESCO Technologies Inc., Televent Git S.A., Badger Meter, Inc., and Roper Industries, Inc.

M.20.2.0 Description of Metric and Measurable Elements

(Metric 20): The total annual venture capital funding of smart grid startups located in the U.S.

M.20.3.0 Deployment Trends and Projections

In recent years, investment in smart-grid technologies has gained traction. In 2008 alone, numerous significant venture capital deals were announced:

- Optimal Technologies International, Inc. received $25 million toward the development of software for managing electrical grids.
- SmartSynch, Inc., secured $20 million to develop wirelessly-communicating meters.
- Trilliant Incorporated secured $40 million toward the development of intelligent networks powering the smart grid.
- Tendrill Networks received $12 million to develop smart grid networking products.
- Fat Spaniel Technologies received $18 million toward the development of an energy-intelligence platform.
- GridPoint, Inc., received $15 million, bringing the firm’s total funding to over $100 million.
- eMeter Corporation secured $12.5 million to support development of advanced metering technologies.

The research team secured venture capital data for the smart grid market from Cleantech Group LLC. The Cleantech Group’s database includes detailed information at the company level from 2000 through the 2nd quarter of 2008. For each transaction, the amount of the transaction, the name of the company, and the company’s focus were identified. Transactions were stratified by year. Based on the data presented by the Cleantech Group, venture-capital funding secured by smart-grid startups was estimated at $194.1 million in 2007 and $129.3 million during the first two quarters of 2008.[288] In total, the Cleantech Group identified 99 deals during the 2000-2008 timeframe totaling $964.4 million (average deal was $9.7 million).

Greentechmedia prepares a report dedicated to tracking venture-capital investment in the energy and power markets. Greentechmedia Venture Power Report covers alternative fuels, solar power, batteries, fuel cells, and other renewable energy sources. One category defined in the report captures funding of startups focused on energy-efficiency, smart-grid, and demand-response technologies. Greentechmedia provided the research team with two Venture Power Reports covering the first two quarters of 2008. The

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[287] Quealy 2007.
[288] E-mail communication with Brian Fan of the Cleantech Group. September 10, 2008.

research team sorted through individual deals listed in the report to identify only smart-grid startups. Based on this approach, the Greentechmedia data suggest that smart grid startups secured $99-$149 million in venture capital funding, with the range resulting from different definitions of what constitutes a smart-grid company.[289]

The National Venture Capital Association (NVCA) publishes quarterly data on venture-capital investment activity in the U.S. in its Money Tree Report. The MoneyTree™ Report is prepared through collaboration between the NVCA and PricewaterhouseCoopers, LLP, and is based on data collected by Thomson Financial. The data used to develop the MoneyTree Report is kept in a database that contains historical data on a quarterly basis back to 1980. Working with the NVCA, the research team queried the database using a number of parameters but was unable to produce reasonable results. The first attempt targeted firms flagged as "Cleantech" with the word "grid" appearing in the business description. We also attempted to use the "Smart Grid" designation as well. Finally, we devised a three-step approach to identifying venture-capital deals. First, we identified several smart-grid companies we knew had recently received venture capital funding. Second, we identified keywords we hoped would capture investment in these types of companies. Specifically, we identified the following keywords:

- [Advanced or Smart or Automated] and [Meters or Grid or Metering or (Energy and Agents)]
- Demand or Load and [Response or (Side and Management)]
- [Energy or Grid or Power] and [Automation or Monitoring or Integration or Communication or Control or Storage or Backup or Remote or (Intelligent Electronic Devices) or (Load Control) or (Load Management) or (Asset Management) or (Management Systems)]
- [Distribution or Building or Home or Residential or Energy] and Automation
- [Distributed or Smart] and [Generation or Appliances or (Motors and Devices) or Storage or (Load Control)]
- Microgrid
- [Electric Vehicle and (Charging or Grid)]

Third, the output of the search was to be compared against both the list of smart-grid companies and a range of plausible investment levels. Unfortunately, the NVCA did not use the keywords outlined above to make an additional query of its database.

Venture-capital funding of smart-grid startups has expanded significantly in recent years. Eric Wesoff of Greentechmedia –who tracks venture-capital funding of smart-grid, demand-response, and energy-efficiency startups – estimated funding in these areas of well under $100 million in 2005, growing to nearly $300 million in 2006 and over $400 million in 2007.[290]

Data provided by Cleantech Group were used to construct Figure M.20.3. Annual venture capital funding levels are presented along with a two-period moving average line. As shown, venture-capital funding of startups slumped between 2000 and 2002 but has since rebounded, growing from $58.4 million in 2002 to $194.1 million in 2007. Cleantech Group data suggest that 2008 funding could well exceed 2007 levels, as venture-capital funding has topped $129 million in the first two quarters of 2008.

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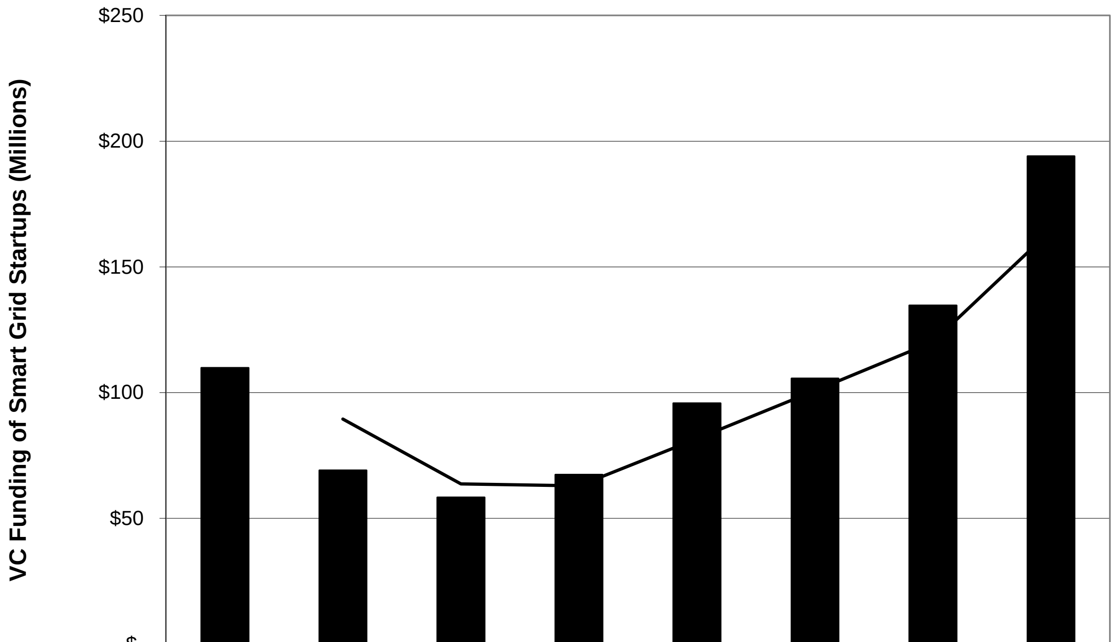
[289]Wesoff, E. 2008a. The Venture Power Report 5 (5). Greentechmedia, Cambridge MA.
[290]Wesoff, E 2008b. The Not so Smart Grid: Utilities and Consumers in the 21st Century.

Between 2002 and 2007, venture-capital funding of smart-grid startups grew at an average annual rate of 27.2 percent.



	2000	2001	2002	2003	2004	2005	2006	2007
VC Funding	109.90	69.15	58.38	67.44	95.81	105.66	134.72	194.05

Figure M.20.2. Venture Capital Funding of Smart Grid Startups (2002-2007)

M.20.3.1 Associated Stakeholders

There are a number of stakeholders whose actions impact the funding of smart-grid startups:

- Regulatory agencies considering smart grid and demand response business cases
- Policymakers interested in using smart-grid technologies to offset future peak-demand growth and reduce the need for investment in supply-side infrastructure.
- Residential, commercial, and industrial customers who may be skeptical of demand-response and smart-grid technologies and their impact on future costs and power reliability
- Electric service providers interested in reducing peak demand and encouraging load shifting
- Products and service suppliers in private industry interested in capitalizing on opportunities with smart-grid technologies
- Venture capital and other investment funds interested in riding the wave of the new technology while yielding potentially significant returns on their investment

M.20.3.2 Regional Influences

Regional influences are reflected both in the presence of programs (e.g., time-of-use pricing, advanced metering) and regulatory structures that advance smart grid investment. The locations of companies engaged in smart grid investment also influence the development of the smart grid. With respect to advanced metering infrastructure (AMI), which is a major driver in smart-grid investment, there are major investment programs underway at a number of utilities:

- The three largest utilities in California are installing millions of smart meters at homes and businesses and charging customers $4.6 billion for the enhanced service.
- Duke Energy Corporation is installing 800,000 smart meters.
- Texas utility Oncor is installing $690 million in smart meters.
- Pacific Gas and Electric Company is retrofitting 9 million meters with communications electronics to enable time-of-use (TOU) pricing.
- The Los Angeles Department of Water and Power has purchased 9,000 smart meters to enable transmission of real-time data through public wireless networks.[291]

Approximately 4.7% of all U.S. customers are currently served by AMI with states in the Mid-Atlantic and Midwest experiencing the highest rates of usage at around 14 percent. California and Texas also represent significant AMI markets.

In addition to AMI, the majority of customers enrolled in TOU programs are located in the Eastern United States in a region stretching from Indiana to New Jersey, and states located to the west of the Rocky Mountains. Smart-communication thermostats are being deployed in California, Maryland, New Jersey, and Texas. Transmission and distribution (T&D) automation is being installed or is under development by Oncor (Texas), Centerpoint Energy (Texas), The Southern Company (Georgia), the Tennessee Valley Authority and ConEdison (New York).[292] Each of these deployments represents an opportunity for smart-grid startups.

The geographic distribution of the opportunities to install smart-grid technologies has correlated with the location of smart-grid startups. Figure M.20.2 presents a map of the U.S. and identifies the locations of the smart-grid startups receiving venture capital during the 2000-2008 timeframe. This map was constructed by the research team using the data provided by the Cleantech Group. As shown, the smart-grid startups are concentrated in southern and eastern states, with some coverage in western states, particularly California. Of the companies included in the venture-funding dataset provided by Cleantech Group, 19 were located outside the U.S; when the company identified a U.S. headquarters, that office was identified in Figure M.20.3. When no U.S. headquarters was identified, the listing was held off the map.

Figure M.20.3. Smart Grid Startup Locations in U.S.

[291]Wesoff, E 2008b.
[292]Silverstein, A. *The Smart Grid and the Utility of the Future.* 2008. Gulf Coast Power Association, Missouri City, Texas. Accessed October 14, 2008 at http://www.gulfcoastpower.org/default/silversteinmay2008.pdf

M.20.4.0 Challenges to Deployment

There are a number of technical and business/financial barriers to implementing smart-grid technologies. These barriers could stall investment in these technologies.

M.20.4.1 Technical Challenges

Technical barriers include:

- It is too early to pick a technological winner in many smart-grid areas, and the lack of a dominant technology generates risk for investors.
- There is presently a patchwork approach to the development of smart-grid alternatives, thus preventing rapid technology change and adoption.
- Utilities have historically been more focused on supply-side solutions and many of the smart-grid technologies support demand-side alternatives.
- Consumers are often confused by, and distrustful of, smart-grid alternatives (e.g., advanced meters, real-time pricing, appliances that communicate with the grid) offered by utilities.

M.20.4.2 Business and Financial Challenges

Business and financial barriers include:

- The ultimate timing in terms of smart-grid technology adoption rates presents a risk to investors who are unwilling to wait 10 to 20 years for an ultimate payoff.
- Regulatory barriers discourage investment in smart-grid technologies.
- Utilities are incentivized in many cases to continue using traditional means of power supply to maximize their own return on investment opportunities.
- Utilities operate in markets with little or no competition, so innovation is not ultimately required due to a lack of competing technologies.

M.20.5.0 Metric Recommendations

The definition of a smart grid company differs between the firms that track venture capital funding. More consideration should be given to defining what constitutes a smart grid startup, and this definition should be developed, refined, and ultimately held constant over time to allow for trend analysis. Further, the approach outlined in Section 3.0 for acquiring data from the National Venture Capital Association should be applied using data from Cleantech Group as a control measure.

Annex B

Electricity Service Provider Interviews

Table of Contents

Table of Figures

Table of Tables

Annex B

Summary of Electricity Service Provider Interviews

B.1 Background Concerning the Interviews

To assess the state of smart-grid deployment, metrics were established to measure these attributes. Data collection for the Smart Grid System Report was performed by interviewing 21 selected electricity-service provider organizations representing a cross section of the industry. As part of the agreement with interviewees, the results were provided to all participants in a blinded form in advance of the report to Congress.

As the interviews only involved energy-service providers, they emphasize aspects of the electric utility enterprise. Other aspects, particularly those of deployment advances on the demand side, were beyond the scope of these interviews.

B.2 Approach

APQC, a productivity-benchmarking and best-practice research firm, was contracted to develop the questionnaire and conduct the interviews. The interview approach followed a four-step benchmarking methodology – plan, collect, analyze and report.

Plan

Planning of the interviews was a joint effort of the interview team with the following tasks:

- Developing an understanding of project-critical success factors and time constraints
- Determining draft content of questions to be asked of participating companies
- Selecting types of representative organizations to target for data collection
- Participating in the Department of Energy Smart Grid Workshop on 19-20 June 2008
- Finalizing metrics and indicators to be collected.

Data Collection

Data collection targeted 21 utilities within the US representing a broad demographic (e.g., coast to coast; small to large; public, private and co-op) and included the following tasks:

- Securing Commitment from Participating Organizations
- Collecting Quantitative Data from Participating Organizations.

Data Validation and Analysis

Data validation and normalization were performed as necessary, along with high level analysis, to ensure the highest quality and accuracy in comparison. Both blinded raw data and aggregated analysis are provided in this report.

Final Report

This report is the final part of the study project, providing a summary of the study itself to augment the data deliverables mentioned above:

- A list of participating organizations
- Data results
- Partner profiles
- Findings and future projections.

B.3 Metrics

Along with the principal characteristics of a smart grid, the interview team aligned the metrics with the Smart Grid Maturity Model created by the Global Intelligent Utility Network Coalition. This model establishes a roadmap for a smart grid within an electric utility at five levels of maturity. It is used to evaluate a utility's current state and map future initiatives. The Smart Grid Maturity Model evaluates each utility against key characteristics in eight domains:

- Strategy, Management and Regulatory
- Organization
- Grid Operations
- Work and Asset Management
- Customer Management and Experience
- Technology
- Value Chain Management
- Societal and Environmental.

The resulting interview form used to collect the data as part of this study can be found in the interview form section below.

B.4 Study Partners

The companies that contributed data to this study by participating in the interviews are listed in Table B.1.

Table B.1. Interview Participants

Company	Size (customers)	Region	Type	Ownership
Atlantic City Electric	540K	NJ	T&D	Public
AEP	5M	Midwest & Central	T&D, Gen	Public
Basin Electric	2.6M	Central	T, Gen	Coop
Bonneville Power Admin	35M	Pacific NW	T	Gov
Centerpoint Energy (SG)	1.9M	TX	D	Public
ComEd	3.2M	NY	T&D, Gen	Public
CoServ Electric	120K	TX	T&D	Coop
Delmarva Power	500K	DE	T&D	Public
DTE Energy	2.2M	MI	T&D, Gen	Public
Duke Energy	3.9M	South & Midwest	T&D, Gen	Public
East Miss EPA	36K	MS	D	Non Profit
Entergy	2.7M	LA, TX, AK, MS	T&D, Gen	Public
First Energy	4.5M	OH, Penn, NJ	T&D, Gen	Public
Kansas City P&L	800K	KS & MO	T&D, Gen	Public
ONCOR Electric Delivery	3M	TX	T&D	Public
Pepco	750K	DC, MD	T&D	Public
Portland General Electric	800K	OR	T&D, Gen	Public
Progress Energy (SG)	3.1M	NC & SC	T&D, Gen	Public
Sempra (SG)	1.4M	CA	T&D, Gen	Public
Southern California Edison	13M	CA	T&D, Gen	Public
Southern Company	4.4M	South	T&D, Gen	Public

These companies represent a significant portion of the US as shown in the Figure B.1 and provide a balanced view of both regulated and deregulated utilities as shown in Figure B.2.

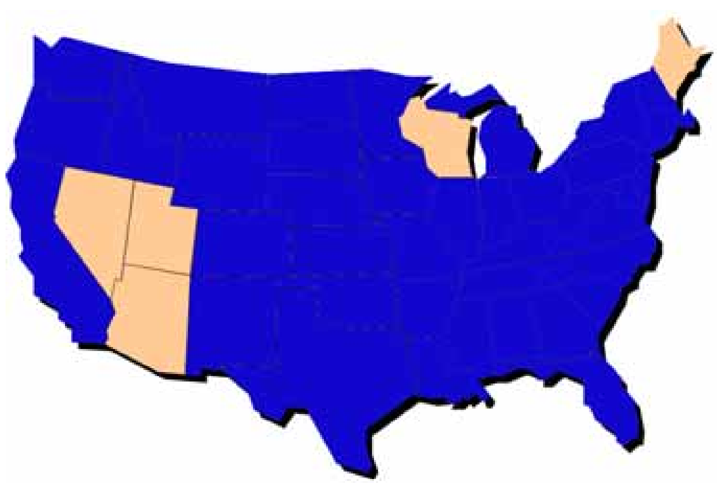


Figure B.1. Coverage of US by Participating Organizations

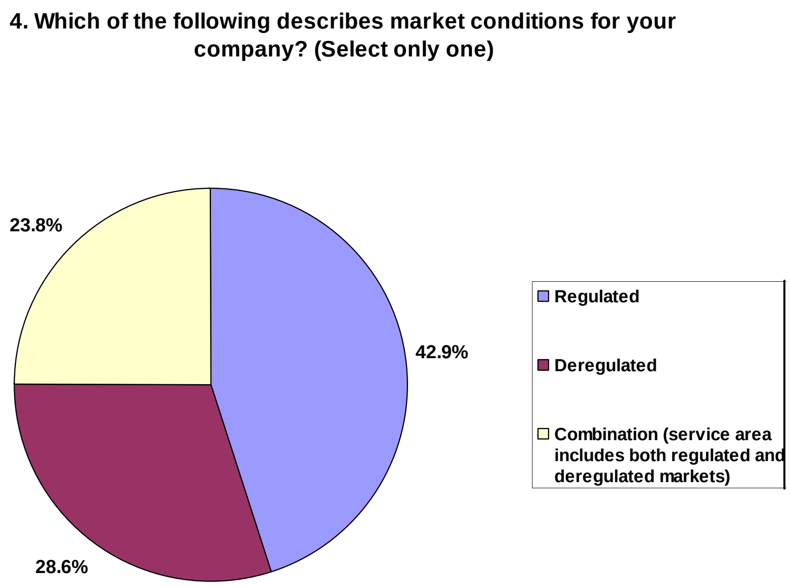


Figure B.2. Market Conditions of Participating Organizations

B.5 Findings

The major insight gained from the data-collection efforts is that deployment of smart-grid capabilities among US electric utilities is in its early stages. Most of the characteristics evaluated show low levels of support and penetration into the marketplace. This does not imply that utilities do not see value in or are not planning these efforts, only that they have not yet moved forward. Some of the key observations are provided here:

- 15% of utilities support remote load control of customers' high-energy devices for more than 10% of their customers
- 15% of utilities have customer participation in demand response greater than 10%
- 15% of utilities have automated response to pricing signals within a premise for greater than 10% of customers
- 5% of utilities have automated response to frequency signals within a premise for greater than 10% of customers
- Deployment of advanced meters is under 1% for residential and commercial customers and under 18% for industrial customers (see Table B.2)
- Less than 1% of lines have dynamic rating capability

Table B.2. Deployment of Advanced Meters

Metric Name	Average	Weighted Average	Weighting Element	Top Performers	Median	Bottom Performers	Count
Advanced meters as a % of total meters (residential)	1.0%	0.2%	residential meters	0.5%	0.2%	0.0%	14
Advanced meters as a % of total meters (commercial)	1.7%	1.0%	commercial meters	1.3%	0.2%	0.0%	11
Advanced meters as a % of total meters (industrial)	42.8%	17.9%	industrial meters	100.0%	13.8%	0.0%	10
Advanced meters as a % of total meters (total)	2.4%	2.7%	total meters	2.8%	0.7%	0.2%	11

There are areas where utilities are moving forward more rapidly; these may indicate either ease of adoption or critical need.

- 70% of utilities have programs to shave peak demand (see Figure B.3)
- 28% of substations are automated and just under 50% have outage detection in place

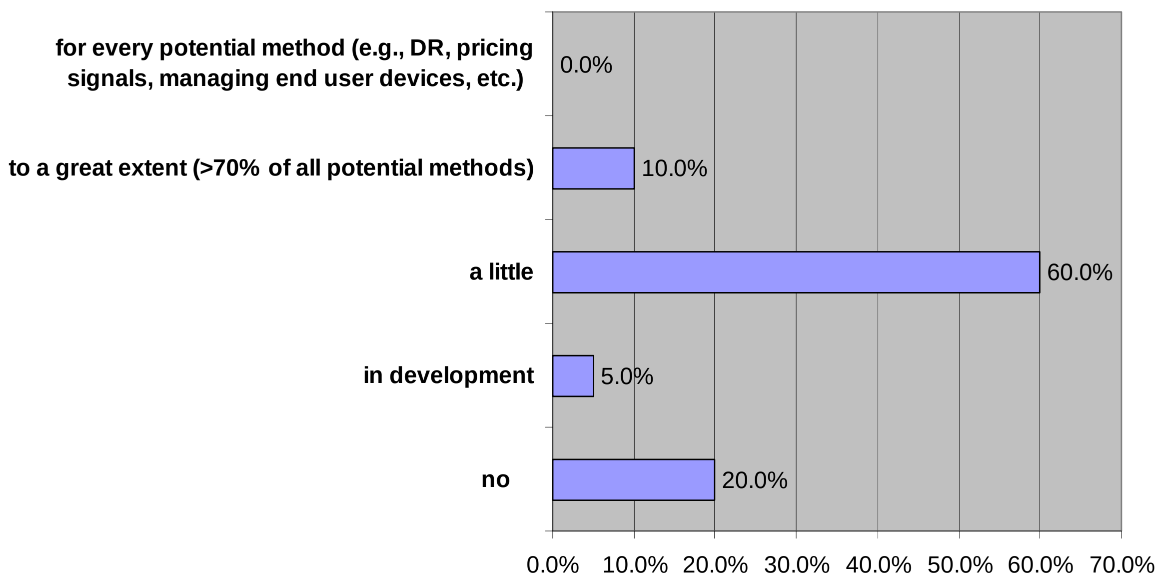


Figure B.3. Programs to Shave Peak Demand

In the following figures, Bottom Performer refers to the performance level below which 25 percent of all responses fall (i.e., 25th percentile), Median is the median performance level for all participants in the database (The median reflects the value below and above which there is an equal number of values.), and Top Performer represents the performance level below which 75 percent of all responses fall (i.e., 75th percentile).

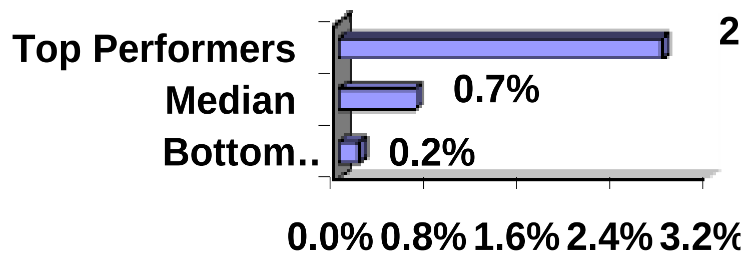


Figure B.4. Advanced Meters as a Percent of Total Meters

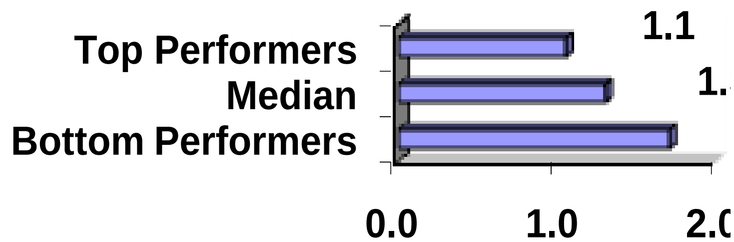


Figure B.5. Actual SAIFI

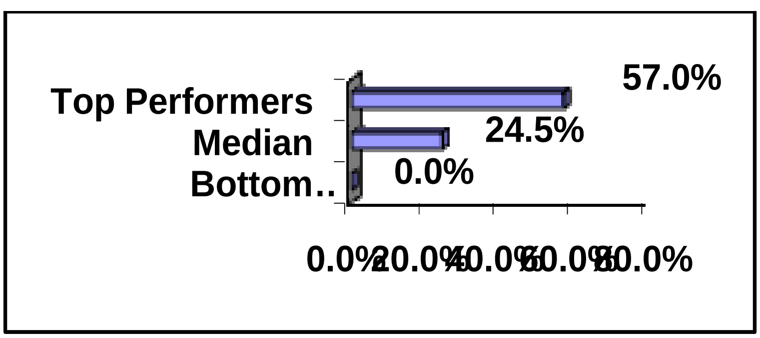


Figure B.6. Percentage of Substations that Are Automated

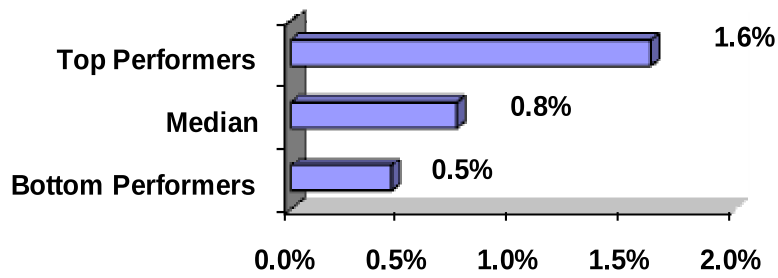


Figure B.7. Percentage of Customer Complaints Related to Power Quality Issues (Excluding Outages)

The full set of results and analysis from the study are provided in the sections that follow. The aggregated responses to both quantitative and qualitative questions are presented.

B.5.1 Interview Questions

Table B.3 lists the questions used in the interviews with electricity service providers. Key terms used in the interview questions are defined below.

- **Industrial customers:** Customers that have factories or are involved in manufacturing; they typically have the highest energy needs. Other customers are residential and commercial
- **Outage detection:** Identification of which circuits are down and the location and possible cause
- **Outage frequency:** Total number of customer interruptions out of the total number of customers over a year; this is the same as SAIFI
- **Regulated/Deregulated:** Supervision of rates, terms and conditions of service, financing, and service areas by a governmental agency; deregulation is the removal or relaxation of regulations or controls
- **Service area (in sq. miles):** The total land area within the scope of operations and control of the utility
- **Substation Automation:** Substation automation goes beyond traditional SCADA to provide added capability and information that can further improve operations and maintenance, increase system and staff efficiencies, and leverage and defer major capital investments. Applications and data of interest may include remote access to IED/relay configuration ports, waveforms, event data, diagnostic information, video for security or equipment-status assessment, metering, switching, volt/VAR management, and others for maintaining uninterrupted power services to the end users
- **Total customer count:** This is the total number of customers (some may have multiple meters, so it is not the meter count)

Table B.3. Interview Form and Questions

Purpose

This study will assess the current status of smart grid development, the prospects for its future, and the obstacles to progress. In addition to assessing the state of smart grid deployments, the survey focuses on the following items:

• the prospects of smart grid development including costs and obstacles,
• regulatory or government barriers, and
• regional issues.

Data provided will be blinded and incorporated into APQC's databases and may be used to support APQC's mission as an education and research organization. All company-specific data collected and maintained for the purposes of this study may be used by APQC consistent with APQC's privacy policy and Benchmarking Code of Conduct (http://www.apqc.org/PDF/code_of_conduct.pdf). For purposes of identifying participating organizations, your organization's name will be listed as a study participant, as appropriate. In exchange for completing this survey, you'll receive a custom report. This study is sponsored by Pacific Northwest National Laboratory in association with the Department of Energy.

General Instructions

1. Answer fields are indicated with blue shading. If you do not have the exact number for an answer, please provide a reasonable approximation. If you cannot provide a reasonable approximation, please leave the answer blank. For multiple select qualitative questions, please place an "x" in the answer box to indicate your selection.
2. Please review the survey scope and definitions for questions before answering. Terms that are highlighted in blue can be clicked for viewing definitions. Please direct survey-related questions to Jeff Varney (jvarney@apqc.org or 512-990-5222).
3. Please ensure all survey responses reflect data for the most recent fiscal year for your organization.
4. Once you have entered your responses in the survey, please review your answers for accuracy and reasonableness.
5. Please do not delete or add rows or columns to this worksheet. It could disrupt hyperlinks.

Survey Scope

Survey pertains to the following deployment attributes associated with transmission & distribution network and generation operations:

• IT Penetration
• Communications Network Capabilities
• Costs
• Obstacles

Table B.3. Interview Form and Questions (continued)

Contact Information:

First Name

Last Name

Title

Company (Include division if applicable)

Address Line 1

Address Line 2

City

State or Province

Phone

Business E-mail (see note below)

Country

Functional Area

Name of Reliability Coordinator

Public or Private Service Provider (indicate one)

1. Please provide the end date of the 12-month period for which you will be providing data in this questionnaire (e.g., 12/31/2007).

Table B.3. Interview Form and Questions (continued)

2. Please provide the following demographic information for your entire company:

a. Percentage of automated substations	
b. Percentage of substations with outage detection	
c. Percentage of circuits with outage detection	
d. Number of electromechanical relays	
e. Number of microprocessor relays	
f. Number of employees (includes temporary, part-time, and full-time)	
g. Megawatts:	
Megawatt hours of generation served	
Peak demand (Megawatt hours)	
Level of distributed generation (Megawatt hours)	
h. Total customer count:	
Residential	
Commercial and Industrial	
i. Meter count:	
Residential	
Total	
Advanced	
Commercial	
Total	
Advanced	
Industrial	
Total	
Advanced	
j. Electric meter count	
k. Size of Service Territory in square miles	
l. Number of substations by voltage class:	
< 13 kV	
>= 13 kV < 35 kV	
>= 35 kV	

4. Which of the following describes market conditions for your company? (*Select only one*)

a. Regulated	
b. Deregulated	
c. Combination (service area includes both regulated and deregulated markets)	

5. In which industry segments does your organization participate? (*Select all that apply*)

a. Generation	
b. Transmission	
c. Distribution	
d. Retail	

6. Do you have dynamic or supply based prices plans? (*Select all that apply)*

a. None	
b. Fixed prices that vary based upon time of use (peak/off peak, day/night, etc.)	
c. Critical peak pricing	
d. Dynamic prices based upon operating or market conditions.	
e. Ability to send price signals to consumers	

Table B.3. Interview Form and Questions (continued)

7. For the following, select all that are enabled through the real-time data sharing from smart grid capabilities you have implemented.

a. New information is flowing across functions and systems	
b. Control analytics has improved cross line of business decision-making	
c. Planning has transitioned from estimation to fact-based	
d. Distributed intelligence and analytics are now available across functions and systems	
e. Distributed intelligence and analytics are now available externally	
f. Coordinated energy management of generation is available throughout your supply chain	

8. What type of regulatory policies (beneficial regulatory treatment for investments made and risk taken) are in place that support smart grid investment by your utility?

a. None	
b. Mandates -- e.g., required installation of smart meters	
c. Incentives	
d. Regulatory recovery	

9. What percentage of your smart grid investment to date has been recovered through rate recovery?

10. What percentage of your smart grid future investment do you expect to recover through rate recovery?

11. Do you have remote load control of customer high energy devices?

a. no	
b. in development	
c. a little (< 10% of all customers)	
d. to a great extent (10% - 70% of all customers)	
e. completely (> 70% of all customers)	

12. Do you have customer participation in demand/response?

a. no	
b. planned	
c. a little (< 10% of all customers)	
d. to a great extent (10% - 70% of all customers)	
e. completely (> 70% of all customers)	

13. Do you have programs to shave peak demand using all potential methods?

a. no	
b. in development	
c. a little	
d. to a great extent (>70% of all potential methods)	
e. for every potential method (e.g., DR, pricing signals, managing end user devices, etc.)	

Table B.3 Interview Form and Questions (continued)

14. What is your capacity for distributed generation as a percentage of total capacity on grid (excludes DG whose operation does not respond to grid conditions and emergency generation capacity)?

15. What is your energy storage capacity as a percentage of total capacity on grid (batteries, flywheels, etc.)?

16. What is your non-dispatchable renewable generation as a percentage of total capacity on grid?

17. Do you have automated response to pricing signals for major energy using devices within a premise?

a. no	
b. in development	
c. a little (10% - 30% of all customers)	
d. to a great extent (30% - 80% of all customers)	
e. completely (> 80% of all customers)	

18. Do you have automated response to frequency signals for energy using devices within a premise?

a. no	
b. in development	
c. a little (10% - 30% of all customers)	
d. to a great extent (30% - 80% of all customers)	
e. completely (> 80% of all customers)	

19. Please provide the following reliability measures:

a. Predicted SAIFI	
b. Actual SAIFI	
c. Predicted SAIDI	
d. Actual SAIDI	
e. Predicted MAIFI	
f. Actual MAIFI	

20. How many advanced measurement devices do you have within your grid?

a. Phasor Measurment Units	
b. Digital Fault Recorders	
c. Other	

Table B.3 Interview Form and Questions (continued)

21. Please provide the following capacity factors.

a. Average load (MW) (sum of all substation average loads)	
b. Peak load (MW) (sum of all substation peak loads)	
c. Capacity (MW) (sum of all substation capacities)	

22. What percentage of your lines have dynamic rating capability?

23. What is the percentage of IEDs with communications on your grid?

24. What is your percentage of customer complaints related to power quality issues (excluding outages)?

25. For each of the following NERC security standards, indicate how frequently you perform assessments.

	Never	Ad hoc	Annually	Quarterly	Monthly
a. CIP-002 Critical Cyber Assets					
b. CIP-003 Security Management Controls					
c. CIP-004 Personnel & Training					
d. CIP-005 Electronic Security					
e. CIP-006 Physical Security of Critical Cyber Assets					
f. CIP-007 Systems Security Management					
g. CIP-008 Incident Reporting and Response Planning					
h. CIP-009 Recovery Plans for Critical Cyber Assets					

26. Have you deployed the following security features? *(Select all that apply)*

a. Intrusion detection	
b. Key management systems	
c. Encrypted communications	
d. Firewalls	
e. Others (Please describe)	

B.5.2 Interview Results

Key Terms

- N: The N value reflects the sample size of a distribution.
- Bottom Performer: This represents the performance level below which 25 percent of all responses fall (i.e., 25th percentile).
- Median: The median performance level for all participants in the database. The median reflects the value below and above which there is an equal number of values.
- Top Performer: This represents the performance level below which 75 percent of all responses fall (i.e., 75th percentile).
- NA: Information is not available.
- Average: The arithmetic mean.
- Weighted average: The calculated value based on a weighting element. Calculation is made by taking a respondent's percentage of total of a weighting element and multiplying that percentage times the company's metric value. The weighted average is the sum of data from all participants that had a metric value.
- All-participants peer group: Reflects all business entities that provided data.

Note: Results in this report are drawn from from relatively small sample sizes. Care should be exercised when applying these results to a larger population.

Scope

Interviews pertained to the following deployment attributes associated with transmission and distribution network and generation operations:

- IT Penetration
- Communications Network Capabilities
- Costs
- Obstacles

Data originated from the following types of operations:

- Transmission & Distribution
- Generation

Table B.4. Summary of Quantitative Data

Metric Name	Average	Weighted Average	Weighting Element	Top Performers	Median	Bottom Performers	Count
Key Performance Indicators							
Advanced meters as a % of total meters (residential)	1.0%	0.2%	residential meters	0.5%	0.2%	0.0%	14
Advanced meters as a % of total meters (commercial)	1.7%	1.0%	commercial meters	1.3%	0.2%	0.0%	11
Advanced meters as a % of total meters (industrial)	42.8%	17.9%	industrial meters	100.0%	13.8%	0.0%	10
Advanced meters as a % of total meters (total)	2.4%	2.7%	total meters	2.8%	0.7%	0.2%	11
Electric meters as a % of total meters (total)	98.3%	95.7%	total meters	100.0%	100.0%	99.5%	8
Percentage of automated substations	32.2%	27.9%	total substations	57.0%	24.5%	0.0%	16
Percentage of substations with outage detection	56.2%	46.4%	total substations	100.0%	53.0%	20.5%	16
Percentage of circuits with outage detection	53.7%	46.2%	total customers	94.0%	55.0%	20.0%	15
Predicted SAIFI	1.0	1.2	total customers	0.8	1.0	1.2	6
Actual SAIFI	1.4	1.3	total customers	1.1	1.3	1.7	19
Predicted SAIDI	106.9	132.5	total customers	69.0	107.8	145.1	6
Actual SAIDI	160.8	157.9	total customers	100.1	150.0	210.0	17
Predicted MAIFI	5.4	8.4	total customers	2.3	4.0	7.8	3
Actual MAIFI	3.6	4.0	total customers	1.3	1.7	5.7	9
Percentage of smart grid investment to date that has been recovered through rate recovery	25.1%	19.8%	total customers	25.8%	0.0%	0.0%	20
Percentage of smart grid future investment expected to be recovered through rate recovery	63.4%	91.3%	total customers	100.0%	100.0%	1.0%	19
Capacity for distributed generation as a percentage of total capacity on grid	0.6%	0.9%	total customers	0.9%	0.5%	0.0%	14
Storage capacity as a percentage of total capacity on grid	0.1%	0.3%	total customers	0.0%	0.0%	0.0%	16
Non-dispatchable renewable generation as a percentage of total capacity on grid	2.4%	3.4%	total customers	3.3%	0.5%	0.0%	16
Percentage of lines that have dynamic rating capability	0.5%	0.3%	total customers	0.0%	0.0%	0.0%	14
Percentage of IEDs with communications on grid	40.5%	28.8%	total customers	69.3%	52.5%	0.6%	14
Percentage of customer complaints related to power quality issues (excluding outages)	4.2%	3.1%	total customers	1.6%	0.8%	0.5%	12
Supporting Indicators							
Residential customers as a % of total customers	89.4%	88.2%	total customers				
Commerical and Industrial customers as a % of total customers	10.5%	11.6%	total customers				
Electromechanical relays as a % of total relays	61.3%	81.2%	total relays				
Microprocessor relays as a % of total relays	51.6%	20.3%	total relays				
Size of Service Territory in square miles per 1000 customers	15.3	12.9	total customers				
Substations by voltage class:							
< 13 kV substations as a % of total substations	32.7%	26.0%	total substations				
>= 13 kV < 35 kV substations as a % of total substations	38.2%	33.4%	total substations				
>= 35 kV substations as a % of total substations	39.1%	42.1%	total substations				

Table B.5. Summary of Qualitative Data

	Count	Frequency Percentage (All Participants)
4. Which of the following describes market conditions for your company? (*Select only one*)		
Regulated	9	42.9%
Deregulated	6	28.6%
Combination (service area includes both regulated and deregulated markets)	5	23.8%
5. In which industry segments does your organization participate? (*Select all that apply*)		
Generation	11	52.4%
Transmission	18	85.7%
Distribution	19	90.5%
Retail	14	66.7%
6. Do you have dynamic or supply based prices plans? (*Select all that apply)*		
None	8	38.1%
Fixed prices that vary based upon time of use (peak/off peak, day/night, etc.)	12	57.1%
Critical peak pricing	3	14.3%
Dynamic prices based upon operating or market conditions.	7	33.3%
Ability to send price signals to consumers	7	33.3%
7. For the following, select all that are enabled through the real-time data sharing from smart grid capabilities you have implemented.		
New information is flowing across functions and systems	9	42.9%
Control analytics has improved cross line of business decision-making	7	33.3%
Planning has transitioned from estimation to fact-based	5	23.8%
Distributed intelligence and analytics are now available across functions and systems	4	19.0%
Distributed intelligence and analytics are now available externally	1	4.8%
Coordinated energy management of generation is available throughout your supply chain	2	9.5%
8. What type of regulatory policies (beneficial regulatory treatment for investments made and risk taken) are in place that support smart grid investment by your utility?		
None	6	28.6%
Mandates -- e.g., required installation of smart meters	4	19.0%
Incentives	3	14.3%
Regulatory recovery	11	52.4%
11. Do you have remote load control of customer high energy devices?		
no	5	23.8%
in development	3	14.3%
a little (< 10% of all customers)	10	47.6%
to a great extent (10% - 70% of all customers)	3	14.3%
completely (> 70% of all customers)	0	0.0%
12. Do you have customer participation in demand/response?		
no	3	14.3%
planned	2	9.5%
a little (< 10% of all customers)	13	61.9%
to a great extent (10% - 70% of all customers)	3	14.3%
completely (> 70% of all customers)	0	0.0%

Table B.5. Summary of Qualitative Data (continued)

13. Do you have programs to shave peak demand using all potential methods?		
no	4	19.0%
in development	1	4.8%
a little	12	57.1%
to a great extent (>70% of all potential methods)	2	9.5%
for every potential method (e.g., DR, pricing signals, managing end user devices, etc.)	0	0.0%
17. Do you have automated response to pricing signals for major energy using devices within a premise?		
no	9	42.9%
in development	9	42.9%
a little (10% - 30% of all customers)	3	14.3%
to a great extent (30% - 80% of all customers)	0	0.0%
completely (> 80% of all customers)	0	0.0%
18. Do you have automated response to frequency signals for energy using devices within a premise?		
no	17	81.0%
in development	3	14.3%
a little (10% - 30% of all customers)	1	4.8%
to a great extent (30% - 80% of all customers)	0	0.0%
completely (> 80% of all customers)	0	0.0%
25. For each of the following NERC security standards, indicate how frequently you perform assessments.		
CIP-002 Critical Cyber Assets		
Never	1	4.8%
Ad hoc	4	19.0%
Annually	12	57.1%
Quarterly	0	0.0%
Monthly	0	0.0%
CIP-003 Security Management Controls		
Never	1	4.8%
Ad hoc	7	33.3%
Annually	8	38.1%
Quarterly	0	0.0%
Monthly	1	4.8%
CIP-004 Personnel & Training		
Never	1	4.8%
Ad hoc	8	38.1%
Annually	6	28.6%
Quarterly	1	4.8%
Monthly	1	4.8%
CIP-005 Electronic Security		
Never	1	4.8%
Ad hoc	6	28.6%
Annually	6	28.6%
Quarterly	2	9.5%
Monthly	0	0.0%

Table B.5. Summary of Qualitative Data (continued)

CIP-006 Physical Security of Critical Cyber Assets		
Never	1	4.8%
Ad hoc	7	33.3%
Annually	5	23.8%
Quarterly	2	9.5%
Monthly	0	0.0%
CIP-007 Systems Security Management		
Never	1	4.8%
Ad hoc	7	33.3%
Annually	7	33.3%
Quarterly	0	0.0%
Monthly	2	9.5%
CIP-008 Incident Reporting and Response Planning		
Never	1	4.8%
Ad hoc	7	33.3%
Annually	7	33.3%
Quarterly	1	4.8%
Monthly	0	0.0%
CIP-009 Recovery Plans for Critical Cyber Assets		
Never	1	4.8%
Ad hoc	7	33.3%
Annually	7	33.3%
Quarterly	1	4.8%
Monthly	0	0.0%
26. Have you deployed the following security features? *(Select all that apply)*		
Intrusion detection	14	66.7%
Key management systems	11	52.4%
Encrypted communications	15	71.4%
Firewalls	20	95.2%
Others (Please describe)	7	33.3%

Graphic Summary of Qualitative Information

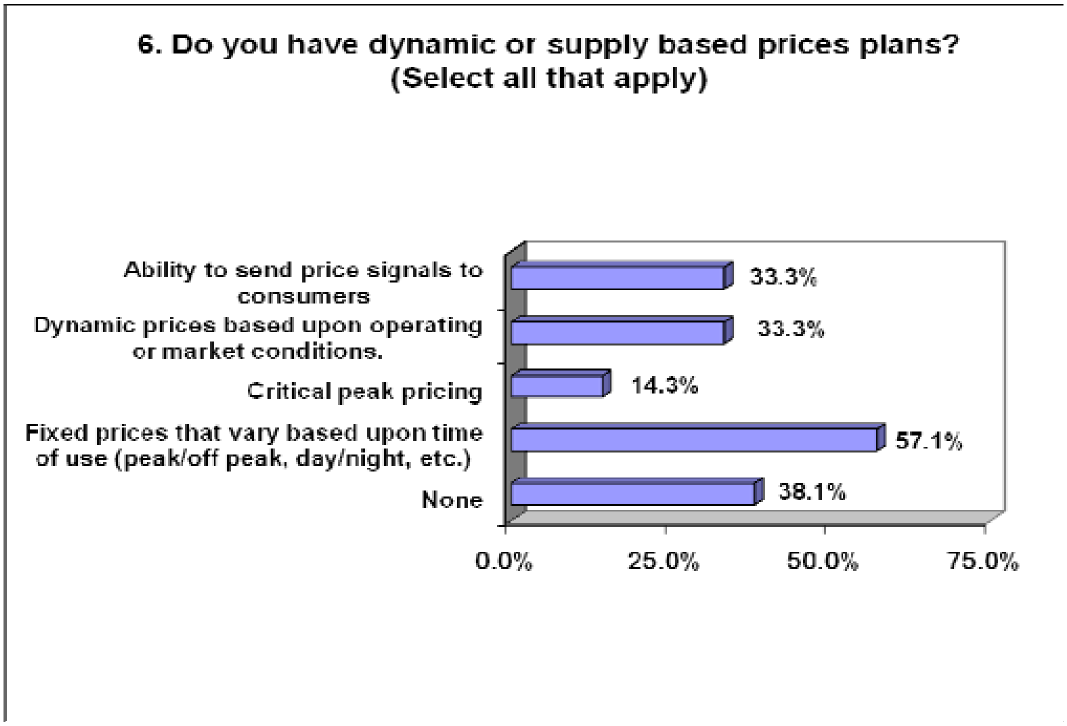


Figure B.8. Percentage of Interviewees With Dynamic or Supply-Based Price Plans

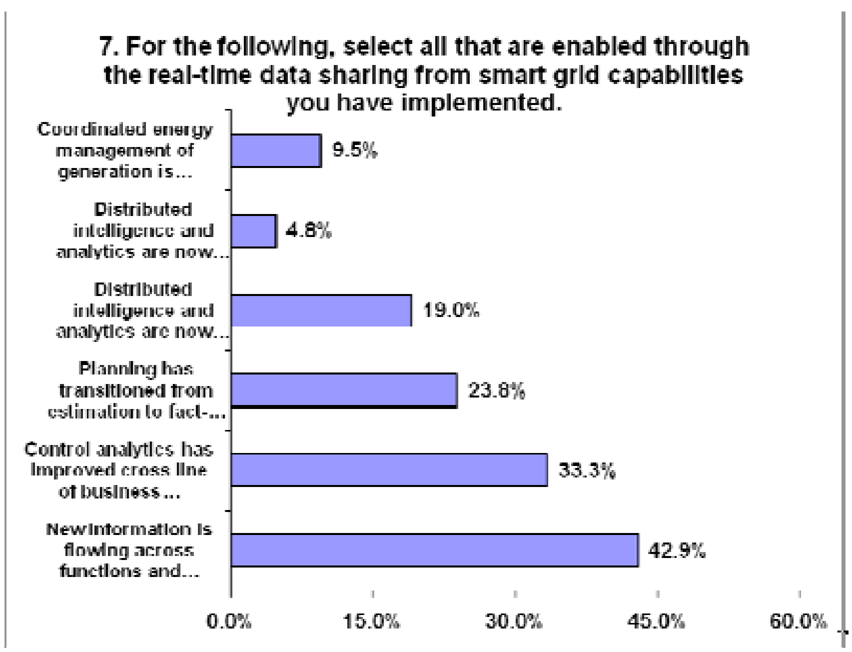


Figure B.9. Smart-Grid Activities Enabled by Smart-Grid Capabilities Implemented

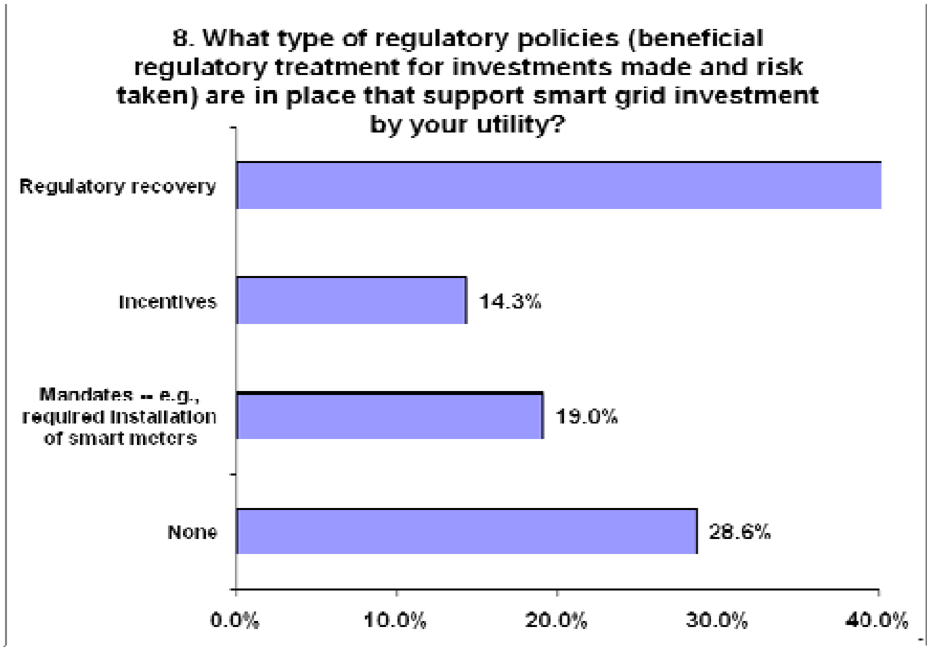


Figure B.10. Types of Regulatory Policies Supporting Smart-Grid Investment

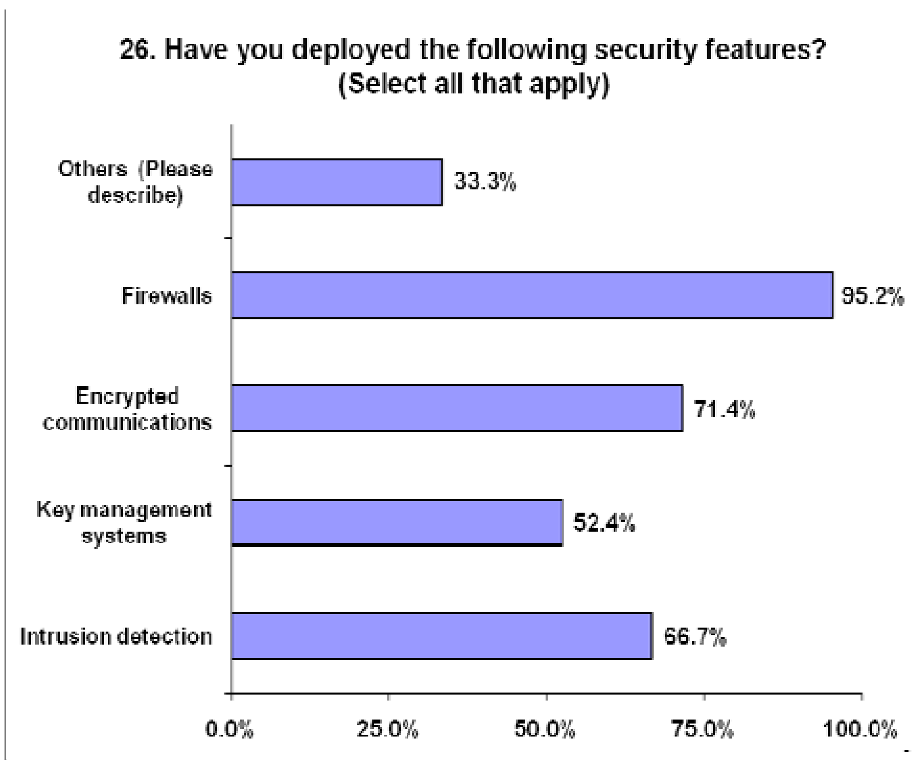


Figure B.11. Types of Security Features Deployed

B.6 Insights for Future Data Collection

An additional objective during the course of the study was to gather insights about the selected metrics and interview questions to support future cycles of data collection and reporting. This was achieved primarily through dialog with and written comments from the participants in the study. The majority of comments centered on two themes: definitions of key terms and evaluation of security.

The most common question from participants was asking for clarification of terms used within the interview. This indicates a need to enhance the glossary of terms and careful selection of wording within questions to promote easy and uniform interpretation among the participants. The most common request for clarification was a definition of “automated meter.”

Automated Meter – any meter that enables communication with both the utility and the end user, enabling capabilities such as smart thermostats and other intelligent devices in a premise, and demand-response schemes and other automated solutions that require bi-directional flow of data to and from a premise.

To complete the interview, most participants distributed it among multiple resources, dividing responsibility for sets of related questions to those that could best answer them. In the case of security, most organizations have a group that is responsible for cyber security. In speaking with those experts, they stressed the complexity of evaluating the current state of security within a utility. In order to evaluate the effectiveness of security that must accompany deployment of smart grid capabilities, they felt more rigorous metrics and interview questions would be necessary. To this end, several of those experts offered assistance in identifying appropriate metrics as part of a future working group.

The basis for the metrics included within this study is the Smart Grid Implementation Workshop sponsored by DOE in June, 2008. The challenge was a compressed timeline that did not allow sufficient analysis and refinement of the metrics and the corresponding approach to gather the data. The duration of data collection also presented a challenge to meet the required reporting date to Congress. Both of these constraints can be solved in future data collection and reporting efforts by allocating sufficient project time. A study of this magnitude will typically take five to six months at a minimum. The biennial nature of this report enables establishment of an approach that allows ample time to plan, collect, analyze, and report.